PER•SE•VER•ANCE:
NOUN. STEADY
PERSISTENCE IN A
COURSE OF ACTION,
A PURPOSE, A STATE,
ETC., ESPECIALLY IN
SPITE OF DIFFICULTIES
OR OBSTACLES.

SEE ALSO;
CELTIC EXPLORATION.

CELTIC EXPLORATION: THE DEFINITION OF ACUMEN, OPPORTUNITY, EXPERIENCE, RESULTS & PERSEVERANCE.

SINCE STARTING CELTIC EXPLORATION IN 2002, OUR VISION HAS BEEN TO APPLY SOUND FINANCIAL PRINCIPLES, ACQUIRE QUALITY ASSETS AND DELIVER SUPERIOR VALUE.

A GLOBAL RECESSION DIDN'T THROW US OFF. WE BOLSTERED OUR HOLDINGS. / LOW NATURAL GAS PRICES WON'T DETER US. WE SEE PREMIUM PRICING FROM OUR LIQUIDS-RICH PLAYS. / CONSTANT CHANGE DOESN'T SCARE US. WE HAVE BUILT IN FLEXIBILITY. / OUR GOAL IS TO PROSPER THROUGH A LARGE DRILLING INVENTORY, LOW COST STRUCTURE AND EXPOSURE TO ROBUST LIQUIDS PRICES. WE ARE PLOTTING OUR FUTURE.

TABLE OF CONTENTS

AC•U•MEN:

NOUN.

KEEN INSIGHT;
SHREWDNESS:
KNOWLEDGE
AND ABILITY TO
MAKE PROFITABLE
BUSINESS
DECISIONS.

SEE ALSO;
CELTIC FINANCIAL
STRATEGY.

CELTIC HISTORICALLY MAINTAINS A STRONG FINANCIAL POSITION THROUGH ITS USE OF EQUITY WHEN NECESSARY AND PRUDENT USE OF BANK DEBT.

Celtic has benefitted significantly through the use of risk management financial instruments and by taking full advantage of government sponsored incentive programs.

Celtic re-allocated valuable financial resources in the second half of 2010. Infrastructure capital required to provide continued production growth at Kaybob was re-allocated to land accumulation at Resthaven in response to an attractive cost environment for land prices and with an outlook to set the Company for continued growth over the next decade.

Increasing shareholder value
Closing stock price at December 31st 2003 — 2010

2010 HIGHLIGHTS

($ thousands, unless otherwise indicated)	Three months ended December 31 2010	2009	Change	Twelve months ended December 31 2010	2009	Change
FINANCIAL						
Revenue, before royalties and financial instruments	**53,042**	60,146	-12%	**222,041**	172,613	29%
Funds from operations	**30,625**	42,003	-27%	**130,793**	118,025	11%
Basic (*$/share*)	**0.34**	0.47	-28%	**1.46**	1.36	7%
Diluted (*$/share*)	**0.33**	0.46	-28%	**1.43**	1.35	6%
Net earnings (loss)	**(3,050)**	907	-	**6,583**	(23,258)	-
Basic (*$/share*)	**(0.03)**	0.01	-	**0.07**	(0.27)	-
Diluted (*$/share*)	**(0.03)**	0.01	-	**0.07**	(0.27)	-
Capital expenditures, net of dispositions and drilling credits	**68,186**	41,519	64%	**172,785**	148,761	16%
Total assets				**723,025**	678,770	7%
Bank debt, net of working capital				**202,683**	168,417	20%
Bank debt, net of working capital, excluding non-cash financial instruments				**200,748**	168,209	19%
Shareholders' equity				**408,095**	387,190	5%
Weighted average common shares outstanding (*thousands*)						
Basic	**90,398**	89,080	1%	**89,876**	86,828	4%
Diluted	**93,118**	90,664	3%	**91,537**	87,500	5%

	Three months ended December 31 2010	2009	Change	Twelve months ended December 31 2010	2009	Change
OPERATIONS						
Production						
Oil (*bbls/d*)	**4,096**	4,384	-7%	**4,070**	3,687	10%
Gas (*mcf/d*)	**79,731**	77,339	3%	**79,404**	63,028	26%
Combined (*BOE/d*)	**17,385**	17,274	1%	**17,304**	14,192	22%
Production per million shares (*BOE/d*)	**192**	194	-1%	**193**	163	18%
Realized sales prices, after financial instruments						
Oil (*$/bbl*)	**68.56**	80.22	-15%	**67.80**	81.00	-16%
Gas (*$/mcf*)	**3.93**	4.86	-19%	**4.37**	4.36	0%
Operating netbacks (*$/BOE*)						
Oil and gas revenue	**33.17**	37.85	-12%	**35.15**	33.33	5%
Realized gain on financial instruments	**1.04**	4.32		**0.85**	7.10	
Realized sales price, after financial instruments	**34.21**	42.17	-19%	**36.00**	40.43	-11%
Royalties	**(3.42)**	(3.21)	7%	**(4.05)**	(4.43)	-9%
Production expense	**(6.47)**	(9.75)	-34%	**(8.13)**	(10.26)	-21%
Transportation expense	**(0.36)**	(0.79)	-54%	**(0.44)**	(0.74)	-41%
Operating netback	**23.96**	28.42	-16%	**23.38**	25.00	-6%
Drilling activity						
Total wells	**15**	17	-12%	**62**	55	13%
Working interest wells	**8.2**	9.6	-15%	**41.9**	43.0	-3%
Success rate on working interest wells	**88%**	100%	-12%	**90%**	91%	-1%
Undeveloped land						
Gross acres				**685,993**	363,473	89%
Net acres				**621,199**	294,700	111%
Reserves						
Oil (*mbbls*)				**16,806**	15,042	12%
Gas (*mmcf*)				**304,197**	272,236	12%
Combined (*mBOE*)				**67,506**	60,415	12%

NET ASSET VALUE PER SHARE AT DECEMBER 31, 2010: $12.32 / NET DEBT OUTSTANDING IN MILLIONS AT DECEMBER 31, 2010: $202.7 / FUNDS FROM OPERATIONS IN MILLIONS GENERATED IN 2010: $130.8 / OPERATING NETBACK PER BOE IN 2010: $23.38

We use our experience to manage our business in a prudent manner so that we thrive in favourable market conditions and stand above the crowd in unfavourable market conditions.

Hedging Strategy in Action

Realized Hedging Gains (Losses) ($ Millions):

2010 / **3.7**

2009 / **34.3**

2008 / **(19.8)**

2007 / **10.3**

2006 / **15.2**

PATIENCE

Impact of The Alberta Royalty Incentive Program

Corporate Royalty Rates (%):

2010 / **11.5%**

2009 / **13.4%**

2008 / **22.4%**

2007 / **21.2%**

2006 / **18.5%**

PERSEVERANCE

OP•POR•TU•NI•TY:

NOUN.

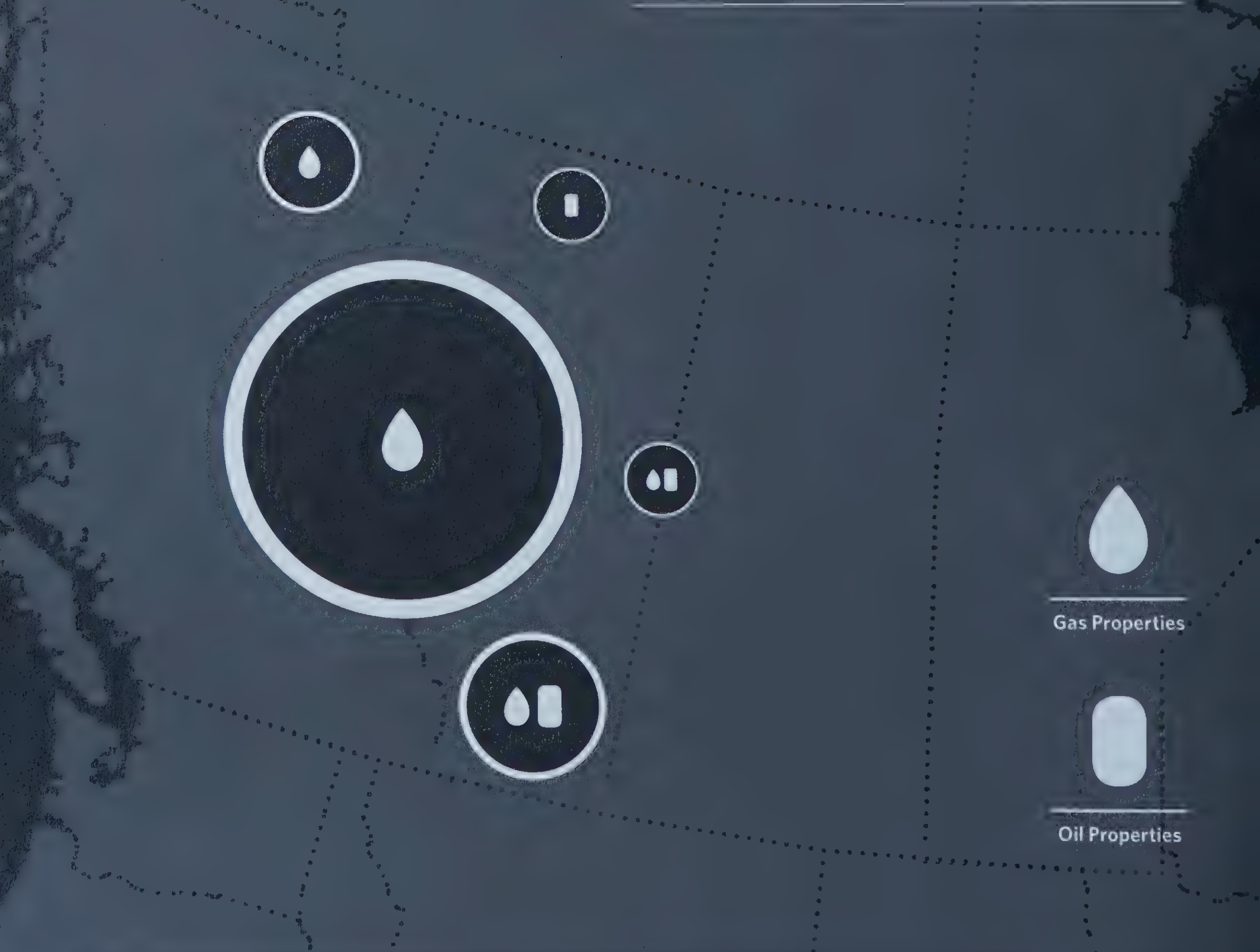
PLURAL; -TIES.

A GOOD POSITION, CHANCE, OR PROSPECT FOR ADVANCEMENT OR SUCCESS.

SEE ALSO;

CELTIC RESOURCE PLAYS.

Focus Area	Percentage of 2010 Production
North East British Columbia Inga	—
Northern Alberta Utikuma	1%
West Central Alberta Kaybob, Fir, Resthaven	92%
East Central Alberta Ashmont, Edwand	1%
Southern Alberta Drumheller, Michichi, Princess, Bantry	6%



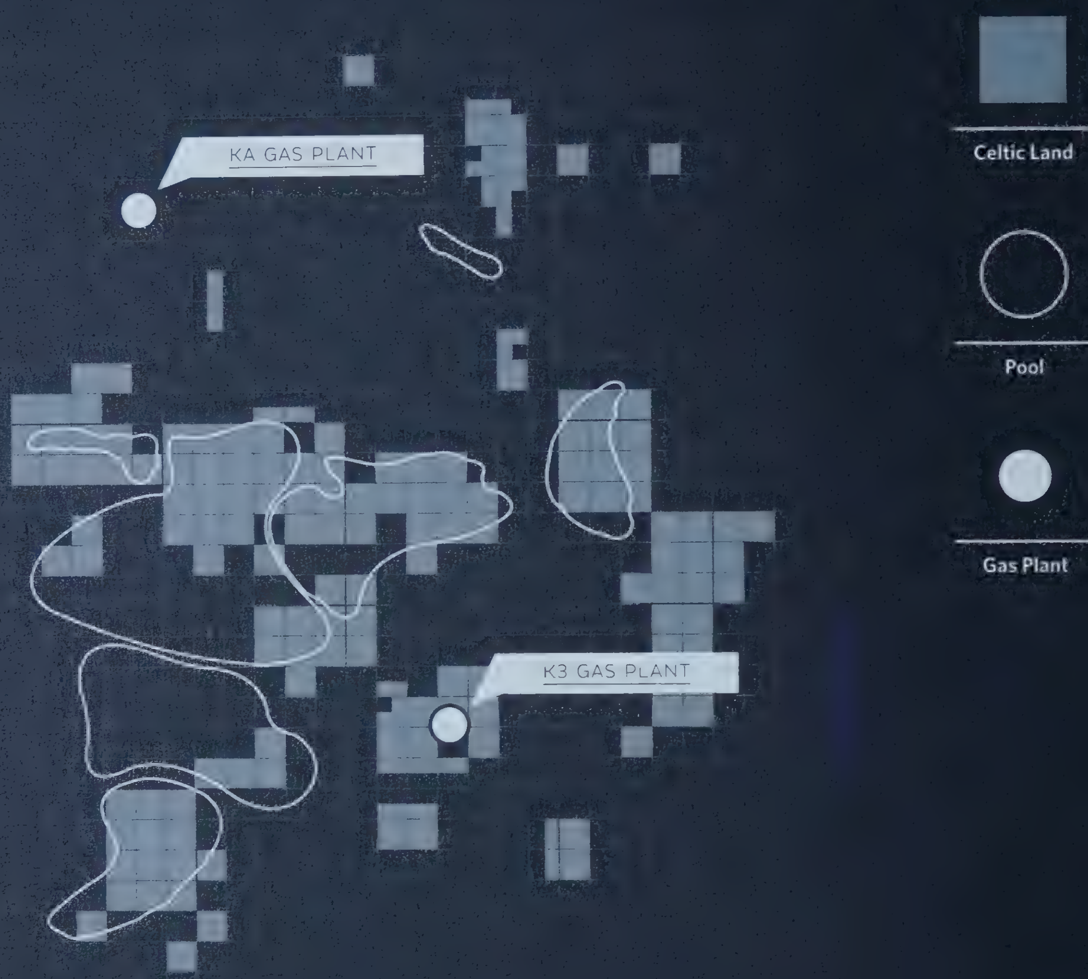
RESOURCE PLAYS HAVE CHANGED THE LANDSCAPE OF THE WESTERN CANADIAN SEDIMENTARY BASIN WHICH WAS PREVIOUSLY VIEWED AS MATURE WITH LIMITED GROWTH OPPORTUNITIES.

NET ACRES OF UNDEVELOPED LAND AT DECEMBER 31, 2010: 621,199 / NET WELLS DRILLED IN 2010: 41.9 / NET DRILLING SUCCESS RATE IN 2010: 90% / PERCENTAGE INCREASE IN PROVED PLUS PROBABLE RESERVES IN 2010: 12%

Horizontal drilling techniques with completions using multi-stage fractures have created opportunities to unlock significant hydrocarbon reservoirs that were previously inaccessible.

Celtic has been a leader using horizontal drilling with multi-stage completions at Kaybob in the Triassic Montney and Cretaceous Bluesky and Notikewin formations. In 2011, Celtic expects to apply its knowledge and experience with exploration at Resthaven in the Triassic Montney and at Kaybob in the Devonian Duvernay, with the objective of ultimately adding new resource plays to the Company's asset base. After drilling numerous wells, Celtic has gained sufficient experience to drill in the most efficient manner, reducing capital costs, ultimately leading to lower finding costs. Examples are the use of multi-pad drilling locations and longer horizontal laterals with a large number of fractures.

Celtic's Montney and Bluesky prospects at Kaybob would have been categorized as conventional reservoirs in the past. However, new technology allows the Company to provide repeatable drilling results and higher recovery rates of gas-in-place, ultimately leading to long-life production categorized as resource plays.



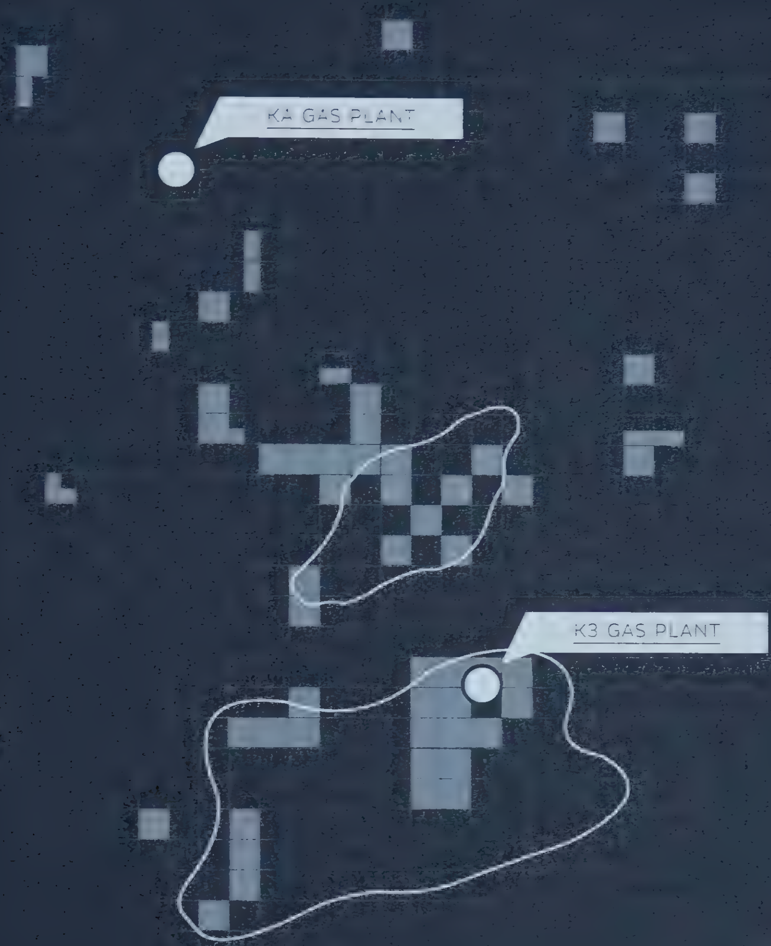
THE KAYBOB MONTNEY PROSPECT WAS CELTIC'S FIRST RESOURCE PLAY THAT HAS BEEN THE COMPANY'S ENGINE FOR GROWTH.

LAND INFORMATION (at December 31, 2010)

90,240 gross acres

78,326 net acres (122 net sections)

Average WI = 87%



LAND INFORMATION
(at December 31, 2010)

33,760 gross acres

20,742 net acres
(32 net sections)

Average WI = 61%

THE KAYBOB BLUESKY PROSPECT FURTHER ENHANCED THE COMPANY'S CORE PRODUCING AREA BY ADDING INCREMENTAL LIQUIDS-RICH NATURAL GAS PRODUCTION.

Kaybob — Devonian Duvernay

THE INDUSTRY HAS INVESTED SIGNIFICANT AMOUNTS IN LAND ACQUISITION FOR DUVERNAY RIGHTS IN THE GREATER KAYBOB AREA. CELTIC EXPECTS TO HAVE AN ACTIVE DRILLING PROGRAM HERE IN THE FIRST HALF OF 2011.

LAND INFORMATION (at December 31, 2010)

106,400 gross acres

88,297 net acres (138 net sections)

RESERVOIR CHARACTERISTICS

Over pressured @ 60 MPa

Wet gas leg is rich in liquids @ 75 bbls/mmcf

Resthaven — Montney

LAND INFORMATION (at December 31, 2010)

384,792 gross acres

383,692 net acres (600 net sections)

RESERVOIR CHARACTERISTICS

Over pressured @ 39 MPa

3% to 10% porosity

CELTIC HAS AMASSED 600 SECTIONS OF LAND WITH MONTNEY RIGHTS AT RESTHAVEN. WITH SUCCESS FROM ITS 2011 DRILLING PROGRAM, THIS AREA COULD PROVIDE THE COMPANY WITH DRILLING INVENTORY AND OPPORTUNITY FOR GROWTH OVER THE NEXT DECADE.

EX•PE•RI•ENCE:

NOUN.

KNOWLEDGE OR PRACTICAL WISDOM GAINED FROM WHAT ONE HAS OBSERVED, ENCOUNTERED, OR UNDERGONE.

SEE ALSO; THE CELTIC TEAM.

CELTIC'S MANAGEMENT AND BOARD OF DIRECTORS IS RESPONSIBLE FOR STEWARDSHIP OF THE COMPANY; SUPERVISING THE MANAGEMENT OF THE BUSINESS AND AFFAIRS OF THE COMPANY; AND PROVIDING LEADERSHIP TO THE COMPANY BY PRACTICING RESPONSIBLE, SUSTAINABLE AND ETHICAL DECISION MAKING.

MANAGEMENT TEAM (LEFT TO RIGHT)

Alan G. Franks
Vice President, Operations

Michael R. Shea
Vice President, Land

Sadiq H. Lalani
Vice President, Finance and Chief Financial Officer

David J. Wilson
President and Chief Executive Officer, Member of the Reserves Committee, Member of the Disclosure Committee, Member of the Board of Directors.

BOARD OF DIRECTORS TEAM

David J. Wilson
President and Chief Executive Officer, Member of the Reserves Committee, Member of the Disclosure Committee, Member of the Board of Directors.

Robert J. Dales
Chairman of the Audit Committee, Member of the Compensation Committee, Member of the Reserves Committee.

Neil G. Sinclair
Chairman of the Compensation Committee, Member of the Audit Committee, Member of the Disclosure Committee.

Eldon A. Mcintyre
Chairman of the Reserves Committee, Member of the Audit Committee, Member of the Compensation Committee.

William C. Guinan
Chairman of the Board and Corporate Secretary, Chairman of the Disclosure Committee.

RE•SULTS:

NOUN.

A DESIRABLE
OR BENEFICIAL
CONSEQUENCE,
OUTCOME, OR
EFFECT.

SEE ALSO;
CELTIC
PERFORMANCE
MEASURES.

CELTIC'S AVERAGE GAS PRICE IN 2010: $4.37 PER mcf

Historical Natural Gas Prices

Alberta AECO-C Average Prices ($/GJ):

2010 / **3.94**

2009 / **3.97**

2008 / **7.73**

2007 / **6.31**

2006 / **6.79**

NET WELLS DRILLED BY CELTIC IN 2010: 41.9

Gas Rig Utilization

US Gas Rotary Rig Count at December 31:

2010 / **919**

2009 / **759**

2008 / **1,347**

2007 / **1,452**

2006 / **1,425**

CELTIC'S AVERAGE DAILY GAS PRODUCTION IN 2010: 79,404 mcf PER DAY

Natural Gas Suppy

US Dry Gas Production (bcf per day):

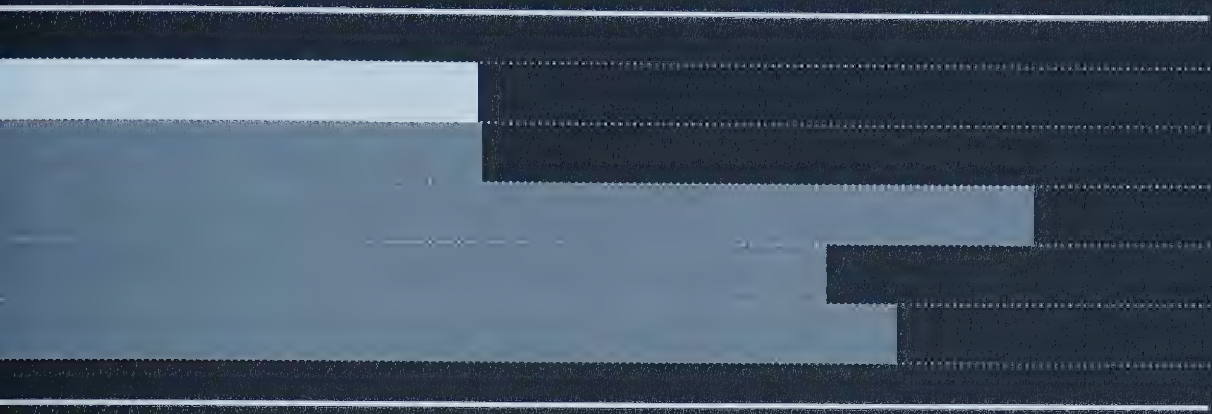
2010 / **59.0**

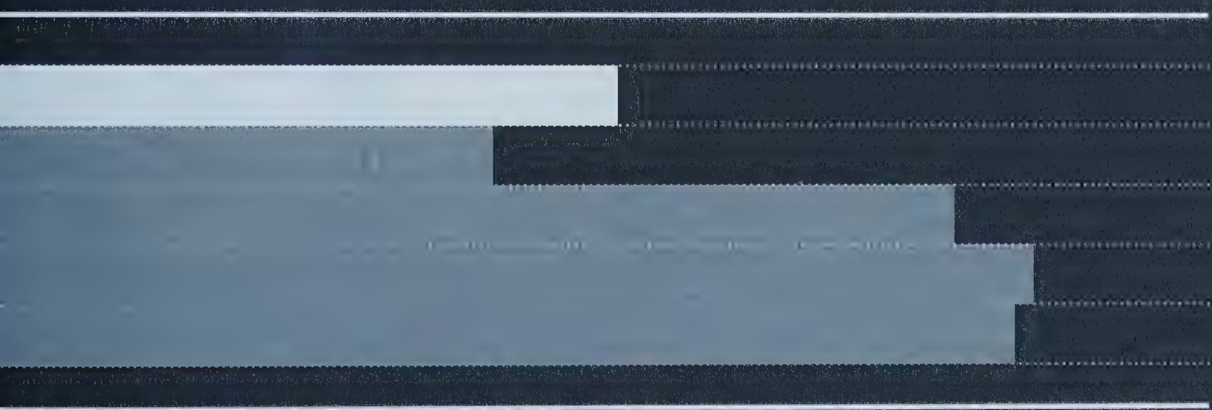
2009 / **56.4**

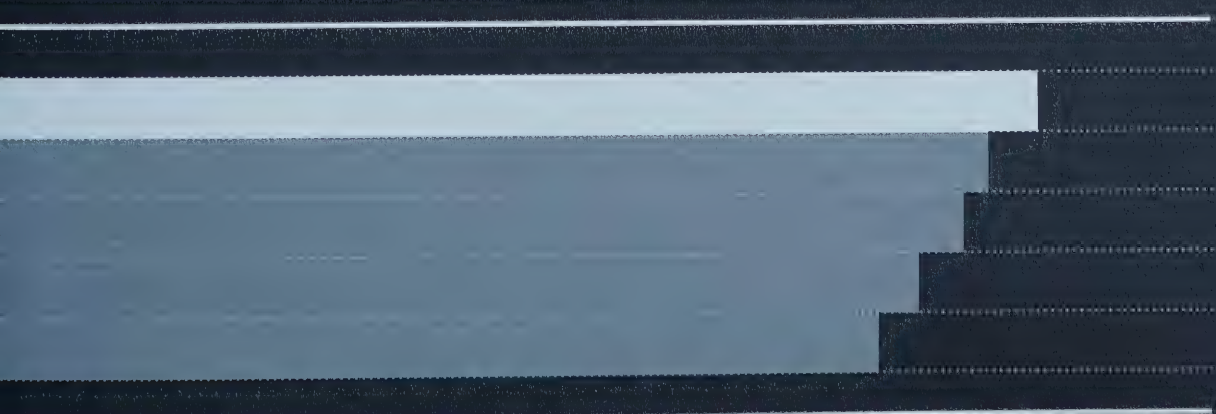
2008 / **55.1**

2007 / **52.8**

2006 / **50.7**







Maintaining Confidence — Production Growth

Since Celtic's first full calendar year of operations in 2003, production has grown at a compound annual growth rate ("CAGR") of 37% from 1,941 BOE per day in 2003 to 17,304 BOE per day in 2010. On a per share basis, production has grown at a CAGR of 24% from 2003 to 2010. Over 80% of the production in 2010 has come from organic growth and the remainder from strategic acquisitions.

Production per Million Shares (BOE/d):

2010 / **193**

2009 / **163**

2008 / **138**

2007 / **111**

2006 / **97**

2005 / **79**

2004 / **70**

2003 / **44**

37%

CAGR in production from 2003 to 2010

24%

CAGR in production per share from 2003 to 2010

791%

Growth in production from 2003 to 2010

17,304

2010 average daily production

Operational Excellence — Reserves Growth

Since December 31, 2003, after Celtic's first full calendar year of operations, reserves have grown at a CAGR of 35% from 8.1 million BOE at December 31, 2003 to 67.5 million BOE at December 31, 2010. On a per share basis, reserves have grown at a CAGR of 25% from December 31, 2003 to December 31, 2010. At December 31, 2010, the net present value of proved plus probable reserves, discounted at 10% before tax, was $0.9 billion, using forecasted 2011 average commodity prices of US$88.40 per barrel for WTI oil and $3.83 per GJ for AECO gas. Celtic's net reserve additions in 2010 replaced production in the year by a factor of 2.1 times.

2P Reserves per thousand Shares (BOE):

2010 / **743**

2009 / **678**

2008 / **649**

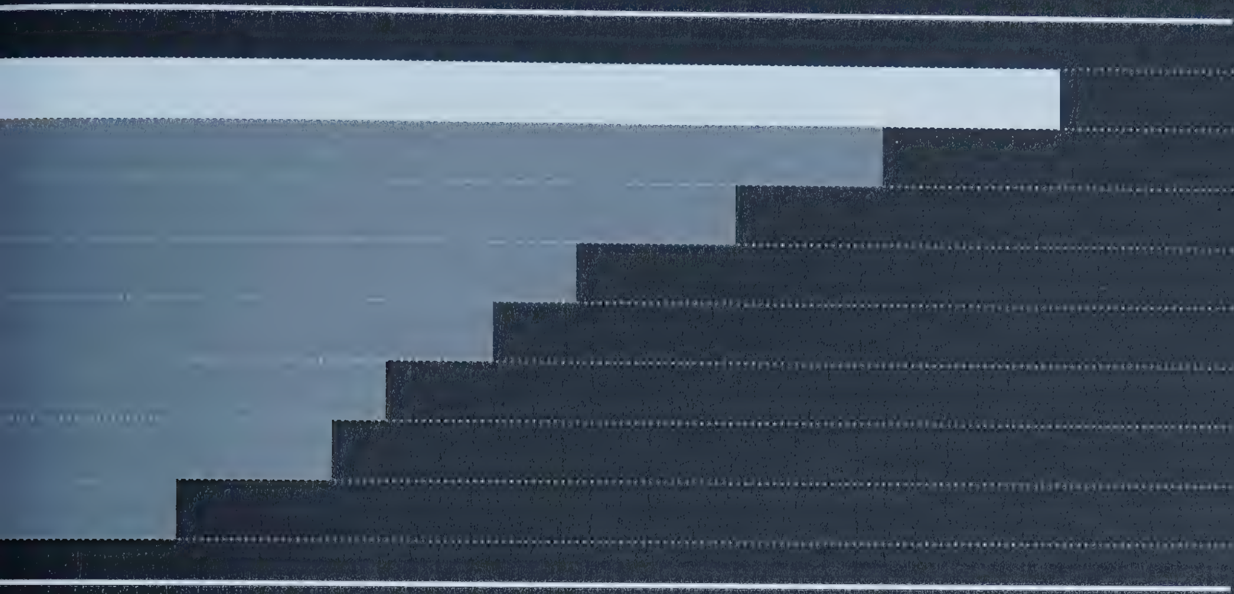
2007 / **448**

2006 / **409**

2005 / **319**

2004 / **214**

2003 / **157**



35%

CAGR in reserves from 2003 to 2010

25%

CAGR in reserves per share from 2003 to 2010

735%

Growth in reserves from December 2003 to December 2010

$930,750

NPV of reserves discounted at 10% BT, as at December 31, 2010 ($ thousands)

Improved Profitability — Funds from Operations Growth

Since Celtic's first full calendar year of operations in 2003, funds from operations ("FFO") has grown at a CAGR of 36% from $15.3 million in 2003 to $130.8 million in 2010. On a per share basis, production has grown at a CAGR of 23% from 2003 to 2010.

In Celtic's guidance for 2011, the Company is forecasting FFO of $159.0 million or $1.70 per share, diluted. This would represent increases of 22% and 19%, respectively, compared to 2010.

FFO per Share (Diluted):

2010 / **$1.43**

2009 / **$1.35**

2008 / **$1.63**

2007 / **$1.16**

2006 / **$1.25**

2005 / **$0.99**

2004 / **$0.68**

2003 / **$0.34**

Adding Shareholder Value

Growth per Share from 2003 to 2010:

24%

CAGR in production per Share

23%

CAGR in Funds from Operations per Share

25%

CAGR in Reserves per Share

Responsible Growth — Recycle Ratio

In 2010, Celtic added 13.4 million BOE of reserves resulting in a finding, development and acquisition ("FD&A") cost of $17.71 per BOE, including future development capital ("FDC") costs. With an operating netback of $23.38 per BOE, the Company's recycle ratio in 2010 was 1.3 times.

Since inception in September 2002, Celtic's FD&A has averaged $14.44 per BOE, including FDC costs, and operating netback has averaged $29.31 per BOE over the same period, resulting in a recycle ratio of 2.0 times.

Operating Netback ($/BOE) / 2P FD&A Cost ($/BOE):

2010 / **1.3x**

2009 / **2.5x**

2008 / **2.9x**

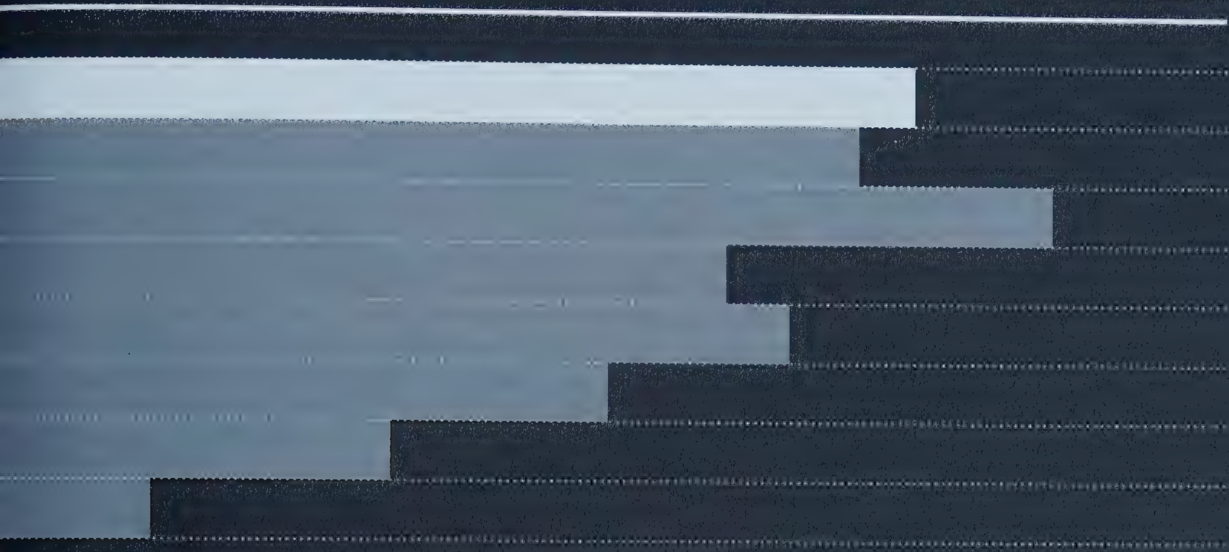
2007 / **1.7x**

2006 / **2.0x**

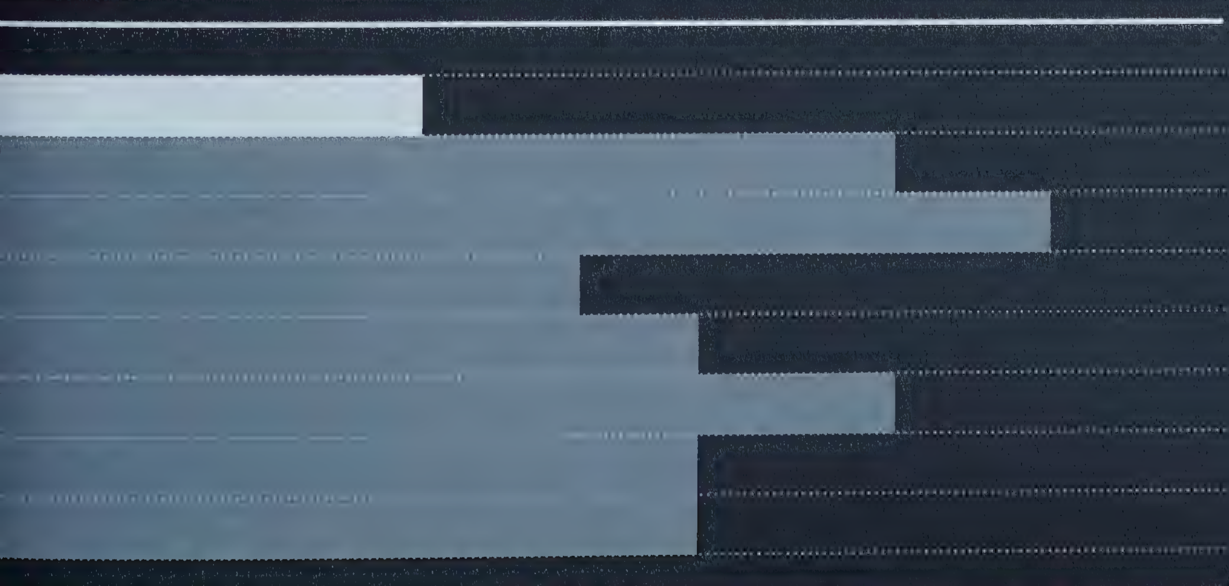
2005 / **2.5x**

2004 / **2.0x**

2003 / **2.0x**



CAGR IN FUNDS FROM OPERATIONS: 36% / GROWTH IN FUNDS FROM OPERATIONS FROM 2003 TO 2010: 754%



PRESIDENT'S MESSAGE

Celtic Exploration Ltd. ("Celtic" or the "Company") is pleased to report to shareholders on the Company's activities. The Company reported growth in production, reserves and funds from operations for the year and at the same time successfully assembled significant land positions in resource plays in the Triassic Montney at Resthaven, Alberta and in the Devonian Duvernay at Kaybob, Alberta.

Highlights for 2010 include year-over-year increases in funds from operations of $130.8 million ($1.43 per share, diluted), net capital expenditures of $172.8 million, increased production of 17,304 BOE per day, increased reserves of 67.5 million BOE, more than doubled undeveloped land holdings of 621,199 net acres and a prudent financial position with debt, net of working capital of $202.7 million or 1.5 times 2010 funds from operations. These results were achieved despite the disposition of non-core assets during the year whereby the Company sold 2.3 million BOE of proved plus probable reserves representing approximately 650 BOE per day of production for net proceeds of $64.6 million.

The year 2010 proved to be a very important year for Celtic as the company set out to establish an opportunity base that will allow it to grow over the next decade. Although the Company was able to tie-up several play types throughout the deep basin of Alberta and British Columbia, two of these growth opportunities can be classified as resource plays that will be the engine for the Company's future growth.

KAYBOB DEVONIAN DUVERNAY RESOURCE PLAY

The Duvernay play in the Kaybob area gained notoriety after an Alberta Crown sale in December 2009, followed by a subsequent Crown sale in July 2010. At these two land sales, $670 million was spent to acquire 388,480 acres at an average price of $1,725 per acre or $1.1 million per section. Sixteen sections adjacent to Celtic lands sold for $2.6 million per section. At December 31, 2010, Celtic owned approximately 88,000 net acres or 138 net sections with Duvernay rights in this area. After drilling and testing the first Duvernay horizontal well in the area during 2010, the Company has continued to accumulate lands in 2011 through farm-in agreements on expiring acreage.

During 2010, Celtic drilled a 33.3% working interest well on an expiring block that was pooled with two other industry partners. Given that this was the first horizontal well into the play, the Company believed it would be financially prudent to jointly test the play. After evaluating the results from this well, the Company drilled a 100% working interest well which was logged and cored through the Duvernay zone with intermediate casing being set above the Duvernay formation, allowing for a horizontal to be drilled in 2011. Celtic has had an opportunity to evaluate the core results from this well and is very encouraged by the permeability and porosity results.

Celtic continues to actively de-risk the play and during the first quarter of 2011 will do so by drilling vertical wells where the Company cores and logs and either vertically completes the well or sets intermediate casing with the intention to drill the well horizontally, after the preferred method of completion has been chosen. It is anticipated that the Company will participate in four drilling operations during the first quarter. One horizontal well which will be completed using the perforate and plug method; two vertical wells which will allow the Company to earn additional acreage; and a fourth vertical well at 100% working interest which will test the oilier part of the play, while at the same time earning additional acreage. After evaluating the results from these wells, Celtic will be in a position to establish a go forward capital expenditure and development plan on this exciting liquids-rich shale play.

RESTHAVEN TRIASSIC MONTNEY RESOURCE PLAY

The second play, which Celtic has been working on for several years but only recently disclosed to the public, is the Resthaven Montney play. The Company first tested a well in this area in 2007, but did not aggressively start pursuing it until 2008, after experiencing positive results from horizontally drilling the same horizon (Montney) on its Kaybob property. With the Company's knowledge in the Kaybob area, it started to acquire a significant acreage position in the Resthaven area prior to drilling a horizontal test in the Montney zone in early 2010. After a favorable flow test, the Company continued to aggressively acquire acreage on the play. The Company currently has 383,692 net acres (600 sections) tied up on the play. An aggressive drilling program is being carried out in 2011, allowing the Company to evaluate this large liquids rich resource play.

Celtic plans to prove up its Resthaven acreage through three approaches. One method will be to drill a vertical strat test, followed by a horizontal well if the results from the strat test are favourable. In some cases, a horizontal well can be drilled adjacent to an existing vertical wellbore, eliminating the need for the initial strat test. Another method is to re-enter existing vertical wellbores that were drilled into a Cretaceous zone and drill down into the Montney formation. In most cases, these are slim hole operations

THE YEAR 2010 PROVED TO BE A VERY IMPORTANT YEAR FOR CELTIC AS THE COMPANY SET OUT TO ESTABLISH AN OPPORTUNITY BASE THAT WILL ALLOW IT TO GROW OVER THE NEXT DECADE.

whereby a valid open hole log can be obtained and the liner can be cemented in place allowing a vertical completion test. The third method that is being used is to re-enter an existing vertical wellbore that was drilled through the Montney formation, exploring for deeper horizons. Most of these type of wells will have intermediate casing set into the Montney formation, providing Celtic with the opportunity to complete and test the previously cased Montney zone.

As Celtic continues to de-risk the Resthaven play, construction of pipeline infrastructure is currently underway, with plans to commence production by mid-year. At present, Celtic plans to produce into existing gas plants in the area until the scope of the development program is fully understood. In the future, the Company could construct its own gas processing facility.

With on-going success, the Resthaven area could provide the Company with drilling inventory that would provide production growth over the next decade at favourable rates of return using current commodity prices.

OTHER PROSPECTS

The Company is also excited about two other plays that are smaller in size in terms of land holdings, however, may also provide significant near term growth and appear to have high liquids potential.

At Inga, British Columbia, Celtic bought a 40% working interest in a 16 section block of land, along with pipeline infrastructure and a 10.0 million cubic feet (gross) per day gas plant. The acreage had been delineated with five vertical wells. After acquiring the property, Celtic participated in the first horizontal well which tested at a rate of 4.7 million cubic feet per day and 1,100 barrels per day of condensate. A follow-up horizontal well will be drilled in the first quarter of 2011 and an additional horizontal well will be drilled on an adjacent three section farm-in block during the summer.

At Fir, Alberta, the Company owns a 100% working interest in 26 sections (16,800 acres) of land with Triassic Montney rights. Celtic discovered a Montney pool at Fir in 2010. This pool which is about 15 miles south west of the Kaybob South Montney pool has similar reservoir characteristics but has higher bottom-hole pressure and a higher liquids yield. Celtic plans to drill three to four wells in this pool in 2011 and plans to tie-in production from the pool prior to break-up.

At Kaybob, Alberta, Celtic continues to be very active on its Montney and Bluesky development programs. As the Company has continued to bring more production on over the last year causing higher line pressures, older wells that have been producing since 2005 to 2008, are backed out of the system. This can be avoided by adding field compression in specific areas along the infrastructure. This had originally been planned for mid-year 2010; however, with Celtic's new plays in the Montney at Resthaven and in the Duvernay at Kaybob, the Company elected to postpone adding field compression and instead directed its capital towards land acquisition and drilling in these new plays. In addition, with better information on the Kaybob Duvernay play, the Company believes that any new infrastructure additions will also be used for future Duvernay production. As a result, compression will have to be designed to accommodate these volumes as well, and therefore adding additional compression will likely be delayed until the second half of 2011, when Duvernay results are better known.

OUTLOOK

Looking ahead to 2011, Celtic will use its knowledge and experience with horizontal multi-stage fracture drilling and completion technologies to move its new prospects forward.

We would like to thank our shareholders for their support, our Board of Directors for their guidance and our employees for their continued effort and loyalty.

David J. Wilson
President and Chief Executive Officer
March 6, 2011

MANAGEMENT'S DISCUSSION & ANALYSIS

INTRODUCTION

The Company was incorporated on April 16, 2002. Celtic's head office is based in Calgary, Alberta, Canada. Common shares of the Company are listed and posted for trading on the Toronto Stock Exchange ("TSX") under the symbol "CLT".

The following management's discussion and analysis ("MD&A") should be read in conjunction with the Company's audited financial statements and related notes for the year ended December 31, 2010. This MD&A is effective March 6, 2011. The accompanying financial statements of Celtic have been prepared by management and approved by the Company's Audit Committee and Board of Directors. These financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). Additional information relating to Celtic can be found on the SEDAR website at www.sedar.com.

NON-GAAP FINANCIAL MEASUREMENTS

This document contains the terms "funds from operations", "operating netback" and "production per share" which do not have a standardized meaning prescribed by Canadian GAAP and therefore may not be comparable with the calculation of similar measures by other companies. Funds from operations and operating netbacks are used by Celtic as key measures of performance. Funds from operations and operating netbacks are not intended to represent operating profits nor should they be viewed as an alternative to cash provided by operating activities, net earnings or other measures of financial performance calculated in accordance with GAAP. Operating netbacks are determined by deducting royalties, production expenses and transportation expenses from oil and gas revenue. Funds from operations are determined by adding back settlement of asset retirement obligations and change in non-cash operating working capital to cash provided by operating activities. The Company calculates funds from operations per share using the same method and shares outstanding which are used in the determination of earnings per share.

OTHER MEASUREMENTS

All dollar amounts are referenced in Canadian dollars, except when noted otherwise. Where amounts are expressed on a barrel of oil equivalent ("BOE") basis, natural gas volumes have been converted to oil equivalence at six thousand cubic feet per barrel and sulphur volumes have been converted to oil equivalence at 0.6 long tons per barrel. The term BOE may be misleading, particularly if used in isolation. A BOE conversion ratio of six thousand cubic feet per barrel is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. References to oil in this discussion include crude oil and natural gas liquids ("NGLs"). NGLs include condensate, propane, butane and ethane. References to gas in this discussion include natural gas and sulphur.

CRITICAL ACCOUNTING ESTIMATES

Management is required to make judgments, assumptions and estimates in the application of generally accepted accounting principles that have a significant impact on the financial results of the Company.

Capitalized costs relating to the exploration and development of oil and gas reserves, along with estimated future capital expenditures required in order to develop proved reserves, are depleted and depreciated on a unit-of-production basis using estimated proved reserves.

The carrying value of property, plant and equipment is reviewed annually for impairment. Impairment occurs when the carrying value of the assets is not recoverable by the future undiscounted cash flows. The impairment loss is limited to the amount by which the carrying amount exceeds: (i) the sum of the fair value of proved plus probable reserves; and (ii) the costs of unproved properties that have been subject to a separate impairment test and contain no probable reserves. The cost recovery ceiling test is based on estimates of proved reserves, production rates, future oil and gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material.

Liability recognition for asset retirement obligations associated with oil and gas well sites and facilities are determined using estimated costs discounted based on the estimated life of the asset using a credit adjusted risk free rate. These capitalized costs

are amortized on a unit-of-production basis, consistent with depletion and depreciation. Over time, the liability is accreted up to the actual expected cash outlay to perform the abandonment and reclamation.

In order to recognize stock based compensation expense, the Company estimates the fair value of stock options granted using the Black-Scholes Model and incorporating assumptions related to interest rates, expected life of the option, volatility of the underlying security and expected dividend yields. These assumptions may vary over time.

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded on Celtic's financial statements.

CHANGES IN ACCOUNTING POLICIES AND PRACTICES

Effective January 1, 2010, the Company adopted the following Canadian Institute of Chartered Accountants ("CICA") Handbook sections:

Section 1582, "Business Combinations", which replaces the previous business combinations standard. The standard requires assets and liabilities acquired in a business combination to be measured at their fair values as of the date of acquisition. The adoption of this standard does not impact Celtic's financial statements at this time.

Section 1601, "Consolidated Financial Statements", which replaces the previous consolidated financial statements standard. This section establishes the requirements for the preparation of consolidated financial statements. The adoption of this section does not impact Celtic's financial statements at this time.

Section 1602, "Non-controlling Interests", which establishes the accounting for a non-controlling interest in a subsidiary to be classified as a separate component of equity. In addition, net earnings and components of other comprehensive income are attributed to both the parent and non-controlling interest. The adoption of this section has no impact on Celtic's financial statements at this time.

FUTURE CHANGES IN ACCOUNTING PRACTICES

In 2008, the CICA's Accounting Standards Board ("AcSB") confirmed that publicly accountable profit-oriented enterprises will be required to use International Financial Reporting Standards ("IFRS") in interim and annual financial statements for fiscal years beginning on or after January 1, 2011.

There can be no guarantee that the International Accounting Standards Board ("IASB") will not make further pronouncements, before the financial statements as at December 31, 2011 are prepared. Consequently, there can be no guarantee that the standards used to prepare the information in this section will not differ from those used to prepare the financial statements for the year ended December 31, 2011, and that the effects described and quantified below will not change.

IFRS CONVERSION PLAN

Although IFRS uses a conceptual framework that is similar to Canadian GAAP, there are differences in recognition, measurement and disclosure which will lead to changes in the Company's financial reporting. This section describes the known impact of the IFRS transition.

The Company has completed the initial diagnostic and study. In this phase major differences between Canadian GAAP and IFRS were identified along with the key areas that would be impacted by the adoption of IFRS. The Company is currently devoting significant resources during the first quarter of 2011 to complete the conversion. In addition, the Company will be taking the filing extension and filing the first quarter 2011 financial statements and MD&A on or before June 15, 2011.

The Company has analyzed the accounting policy choices available under IFRS and selected the ones best suited for its operations. At this time the Company is in the late stages of internal approval and discussing the choices with its external auditors.

The Company has selected the IFRS 1 'First-time Adoption of International Reporting Standards' elections and is in the process of approving the selections and impacts on the opening balance sheet as at January 1, 2010.

During the first five months of 2011, the Company will be:

- Finalizing changes to its accounting policies, along with related changes in previously reported amounts, and drafting new notes to the financial statements.
- Finalizing changes to its information technology to ensure accurate reporting of its financial statement information under IFRS.
- Continuing to train its employees who are affected by IFRS including those outside of the accounting department.
- Reviewing the impact of IFRS on financial covenants, once the opening balance sheet has been finalized. The Company will continue to review the impact of IFRS through its transition of 2010 and will work with its lenders to ensure that any agreements are updated where required.
- Working on developing investor and analyst presentations to explain all changes to the Financial Statements due to IFRS.

Internal Controls and Disclosure Controls

The Company is monitoring the impact of IFRS on internal controls over financial reporting ("ICFR") and disclosure controls and procedures ("DC&P") during the conversion process. As the Company finalizes its conversion, the ICFR documentation will be reviewed and the areas identified as requiring amendments or requiring controls added will be updated. As IFRS will result in increased note disclosure the company is assessing the impact of the transition to IFRS on its DC&P. No material changes in the ICFR or DC&P are expected as a result of transition to IFRS.

Explanation of transition to IFRS

The transition to IFRS requires the Company to apply IFRS 1 'First-Time Adoption of International Financial Reporting Standards,' which sets out the procedures for preparing IFRS-compliant financial statements in the first reporting period after the changeover date (January 1, 2010). IFRS 1 applies only at the time of changeover, and includes a series of optional exemptions from retrospective application to ease the transition to the full set of IFRS.

The Company has determined the areas where changes in accounting policy are expected. The following section discuss the qualitative transition effects and where available, the estimates of the quantifiable effects as of the transition date and expected effects on the 2010 financial statements.

Property, Plant and Equipment ("PP&E")

Under Canadian GAAP, the Company follows the full cost method of accounting for oil and gas operations whereby all costs related to the acquisition or, exploration for and development of oil and gas reserves are capitalized. Depletion is computed using the unit-of-production method based on gross estimated proved oil and gas reserves.

Under IFRS, the Company will be required to adopt new accounting policies for upstream activities.

Pre-exploration costs are those expenditures incurred prior to obtaining the legal right to explore and must be expensed under IFRS. Exploration and evaluation costs are those expenditures for an area or project for which technical feasibility and commercial viability have not yet been determined. Under IFRS, the Company will capitalize these costs as exploration and evaluation assets on the balance sheet. When the area or project is determined to be technically feasible and commercially viable, the costs will be transferred to PP&E and depleted. Unrecoverable exploration and evaluation costs associated with an area or project will be impaired.

Development costs include those expenditures for areas or projects where technical feasibility and commercial viability have been determined. Under IFRS, the Company will continue to capitalize these costs within PP&E and on the balance sheet. However, the costs will be depleted on a unit-of-production basis over an area instead of the gross estimated proved oil and gas reserves for the Company as a whole.

Under IFRS, upstream divestitures will generally result in a gain or loss recognized in net earnings. The Company will adopt the IFRS 1 exemption, which allows the Company to deem the costs of its IFRS upstream assets as at January 1, 2010 to be equal to its Canadian GAAP historical upstream net book value. The Company has allocated its oil and gas assets based on reserves to establish depletion units at an area level.

In 2010, the Company divested several upstream assets, which will lead to recognizing a gain or loss in net earnings, under IFRS. In addition, as the Company will be depleting the assets based on each area's unit-of-production. This will result in a difference in the amount of depletion under IFRS compared to the amount recorded under Canadian GAAP. These amounts have not yet been determined.

Impairment

Under Canadian GAAP, the Company is required to recognize an upstream impairment loss if the carrying value exceeds the undiscounted cash flows of proved reserves at a country level. If an impairment loss is to be recognized, it is then measured at the amount the carrying value exceeds the sum of the present value discounted at a risk-free rate of the proved plus probable reserves and the costs of unproved properties.

Under IFRS, the Company is required to recognize an upstream impairment loss if the carrying value exceeds the recoverable amount for a cash-generating-unit ("CGU"). The recoverable amount is the higher of fair value less cost to sell or value in use. Impairment losses, other than goodwill, are reversed when there is an increase in the recoverable amount.

Based on the work completed, the Company expects to impair certain undeveloped land where the lease was set to expire in 2010 and the Company had made the decision not to pursue renewing the lease. It is expected that this will lead to an impairment of an estimated $1.0 million. The Company has completed an impairment test on all its CGUs and has determined that one CGU may require an estimated impairment of under $3.0 million. After the amounts of these impairments are finalized, the Company does not expect to recognize other impairments on the IFRS opening balance sheet as at January 1, 2010. During the preparation of IFRS annual 2010 financial statements, the Company expects to record impairment in undeveloped land where the leases are expiring during 2011 and the Company does not intend to renew these lease or licenses.

Decommissioning Liabilities/Asset Retirement Obligation ("ARO")

Under Canadian GAAP, ARO is measured as the estimated fair value of the retirement and decommissioning expenditures expected to be incurred. Under IFRS, ARO is measured as the best estimate of the expenditure to be incurred and requires the use of a risk-free discount rate at each re-measurement date. The change in discount rates normally results in a balance being added or deducted to PP&E.

As a result of the Company's use of the IFRS 1 upstream asset exemption, the Company is required to revalue its ARO balance as at January 1, 2010 and recognize the adjustment in retained earnings. The Company expects to recognize an increase in the obligation of less than $13.0 million with a corresponding reduction to retained earnings on the IFRS opening balance sheet as at January 1, 2010.

During 2010, the change to a risk-free discount rate will affect the amount of accretion that is recognized in the financial statements each quarter. The effect of this change has not been fully calculated at this time.

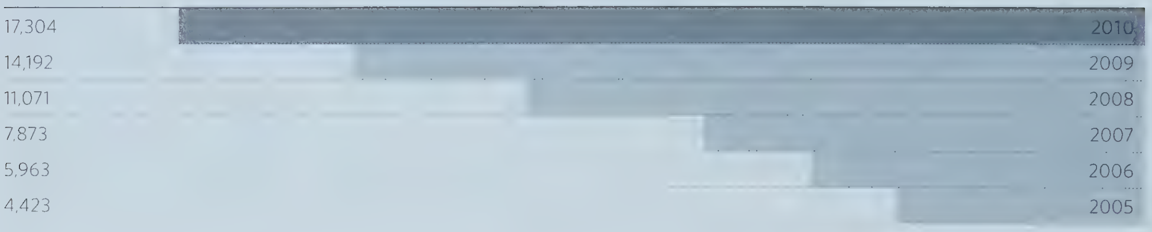
Share-Based Payments

Under Canadian GAAP, the Company recognizes stock based compensation expenses on a straight line basis. Under IFRS, the Company is required to apply graded vesting which requires each installment of a graded vesting award to be treated a separate grant.

The Company will use the IFRS 1 exemption under which share units that were vested prior to January 1, 2010 are not required to be retrospectively restated. The impact to the Company's financial statements has not been determined at this time.

During 2010, there will be a difference in stock based compensation expense charged each quarter to net income under IFRS, compared to Canadian GAAP.

Production — (BOE/d) 2005 — 2010



Leases

Under Canadian GAAP, certain leases were classified as operating leases rather than capital (finance) leases.

Under IFRS, the Company could potentially require the lease to be recognized as an asset with a corresponding liability.

As the majority of the Company's leases expired during 2010, there are no expected changes to the Company's opening balance sheet in regards to leases being assessed as finance leases. However, as the Company initiated several new leases during 2010, these new leases will be assessed under IFRS and the Company expects that in certain cases the leases may be reclassified as finance leases.

Income Taxes

In transition to IFRS, the Company's future income tax liability will be impacted by the tax effects resulting from the IFRS changes discussed in this section of the MD&A. The tax effect resulting from IFRS changes have not been analyzed at this date. In addition, while Canadian GAAP separated future income taxes between current and non-current, IFRS allows only for the presentation of non-current future income tax assets and liabilities.

Other exemptions and policies

The impact to the Company's financial statements and related notes with respect to the remaining IFRS 1 exemptions and other accounting policy choices, have not been determined at this time.

Future International Financial Reporting Standards

IFRS that are mandatory at the changeover date are finalized; however, the IASB's work plan currently has projects underway that are expected to result in new pronouncements that continue to evolve IFRS. The IASB has issued exposure drafts on financial instruments, consolidation, fair value measurement, financial statement presentation, leases, revenue recognition, joint ventures and post-employment benefits, with the final IFRS standards expected to be released during 2011. The Company will be reviewing the standards when released to determine if early adoption is permitted and if it is beneficial to the Company to early adopt such standards.

DISCLOSURE CONTROLS AND PROCEDURES

The Chief Executive Officer ("CEO") and the Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures as defined in National Instrument 52-109 of the Canadian Securities Administrators, to provide reasonable assurance that: (i) material information relating to the Company is made known to the CEO and the CFO by others, particularly during the period in which the interim filings are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation.

The CEO and CFO have evaluated the effectiveness of Celtic's disclosure controls and procedures as at December 31, 2010 and have concluded that such disclosure controls and procedures are effective.

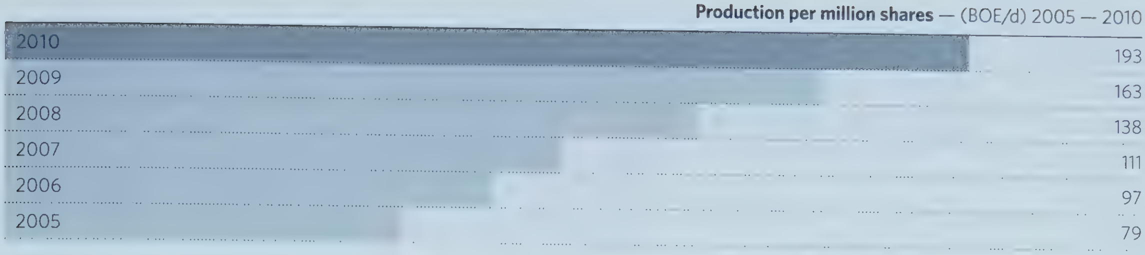
INTERNAL CONTROLS OVER FINANCIAL REPORTING

The CEO and the CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting as defined in National Instrument 52-109 of the Canadian Securities Administrators, in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP.

The Company is required to disclose any change in the Company's internal controls over financial reporting that occurred during the period from October 1, 2010 to December 31, 2010 that has materially affected, or is reasonably likely to materially affect, the Company's internal controls over financial reporting. No material changes were identified during this period.

The CEO and CFO have evaluated the effectiveness of Celtic's internal controls over financial reporting as at December 31, 2010 and have concluded that such internal controls over financial reporting are effective.

Production per million shares — (BOE/d) 2005 — 2010



Due to its inherent limitations, internal controls over financial reporting may not prevent or detect misstatements. In addition, projections of any evaluation relating to the effectiveness in future periods are subject to the risk that controls may become inadequate as a result of changes in conditions, or that the degree of compliance with policies and procedures may deteriorate.

GROWTH STRATEGY

The Company implements a full cycle exploration and development program and, at the same time, opportunistically seeks to acquire assets with exploitation potential. This strategy has proved successful to date as is evidenced by Celtic's rapid growth since commencing active oil and gas operations in September 2002. To complement this strategy, the Company has assembled and retained a team of experienced and qualified personnel and is well positioned financially to act quickly on new opportunities.

RESULTS OF OPERATIONS

2010 HIGHLIGHTS

The year ended December 31, 2010 was another successful year in the execution of the Company's growth strategy. Highlights for 2010 are as follows:

- Drilled 62 (41.9 net working interest) wells during 2010 resulting in 54 (34.3 net) gas wells, 2 (1.6 net) coal bed methane wells and 2 (2.0 net) oil wells, for an overall success rate, based on net wells, of 90%;
- Increased average daily production by 22% to 17,304 BOE per day, up from 14,192 BOE per day in 2009 and achieved daily average production per million shares of 193 BOE per day, up 18% in 2010 compared to 163 BOE per day in the previous year;
- Increased proved plus probable reserves by 12% to 67.5 million BOE, up from 60.4 million BOE at December 31, 2009 and replaced 2010 production by a factor of 2.1 times;
- Reported finding, development and acquisition cost (including future development capital expenditures) of $17.71 per BOE resulting in a recycle ratio of 1.3 times based on proved plus probable reserves;
- Reported net asset value at year-end of $12.56 per share, based on net present value of reserves discounted at 10%, before tax and using forecasted 2011 average commodity prices of US$88.40 per barrel for WTI oil and $3.83 per GJ for AECO gas;
- Reported funds from operations per share, diluted, of $1.43, an increase of 6% from $1.35 per share in the previous year; and
- Assembled significant undeveloped land positions in new resource play prospects targeting the Triassic Montney and Devonian Duvernay formations in west central Alberta resulting in net undeveloped land holdings of 621,199 acres at December 31, 2010, an increase of 111% from December 31, 2009.

PRODUCTION

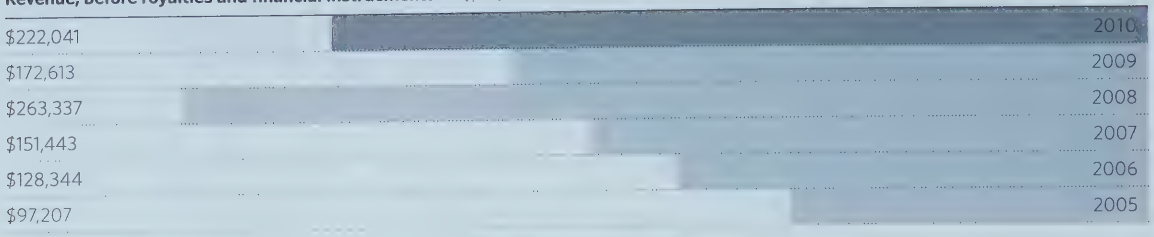
Oil and gas production in 2010 increased 22% to average 17,304 BOE per day compared to 14,192 BOE per day in 2009. Average production in the fourth quarter of 2010 was 17,385 BOE per day, up 1% from 17,274 BOE per day in the fourth quarter of 2009. Production per million shares outstanding in 2010 averaged 193 BOE per day, up 18% from 163 BOE per day in 2009.

The following table provides a summary of daily average production for 2010 and 2009:

PRODUCTION SUMMARY	Year ended December 31, 2010	Year ended December 31, 2009	Percent Change
Oil *(bbls/d)*	4,070	3,687	10%
Gas *(mcf/d)*	79,404	63,028	26%
Combined *(BOE/d)*	**17,304**	**14,192**	**22%**
Production per million shares *(BOE/d)*	**193**	**163**	**18%**

Celtic's production is entirely based in Alberta and is divided into one core area and three minor areas. In Southern Alberta, the Company's primary natural gas producing properties are located at Drumheller, Michichi and Richdale and its primary oil producing properties are located at Princess and Bantry. In East Central Alberta, the principal producing asset is a shallow natural

Revenue, before royalties and financial instrucments — ($M) 2005 — 2010



gas property at Ashmont and Figure Lake. In Northern Alberta, the Company produces mainly light oil from Utikuma Lake. Celtic's core operating area is in West Central Alberta, where the Company has liquids-rich natural gas production in the greater Kaybob area and exploration activity in the greater Resthaven area. West Central Alberta was the Company's most active drilling area in 2010 and approximately 92% of Celtic's production in 2010 came from this area.

The following table provides a summary of comparative daily average production in each core area:

PRINCIPAL PRODUCING AREAS *(BOE/d)*	Year ended December 31, 2010	Year ended December 31, 2009	Percent Change
West Central Alberta	15,874	12,655	25%
Southern Alberta	995	1,042	-4%
East Central Alberta	245	288	-15%
Northern Alberta	190	207	-8%
Total	**17,304**	**14,192**	**22%**

REVENUE

Revenue, before royalties, and before realized and unrealized gains or losses on financial instruments, for the year ended December 31, 2010 was $222.0 million, an increase of 29% compared to $172.6 million in the previous year. For the three months ended December 31, 2010, revenue was $53.0 million, down 12% from $60.1 million in the fourth quarter of 2009.

The breakdown of revenue for 2010 and 2009 is summarized in the following table:

REVENUE	Year ended December 31, 2010		Year ended December 31, 2009		Percent Change	
	$ thousands	$/BOE	$ thousands	$/BOE	$ thousands	$/BOE
Oil revenue	100,084	67.38	75,971	56.45	32%	19%
Gas revenue	121,957	25.25	96,642	25.21	26%	0%
Royalties	(25,592)	(4.05)	(22,968)	(4.43)	11%	-9%
Realized gain (loss) on financial instruments	3,693	0.85	34,294	7.10	-	-
Unrealized gain (loss) on financial instruments	(2,339)	(0.37)	(33,523)	(6.47)	-	-
Revenue	**197,803**	**31.58**	**150,416**	**29.53**	**32%**	**7%**

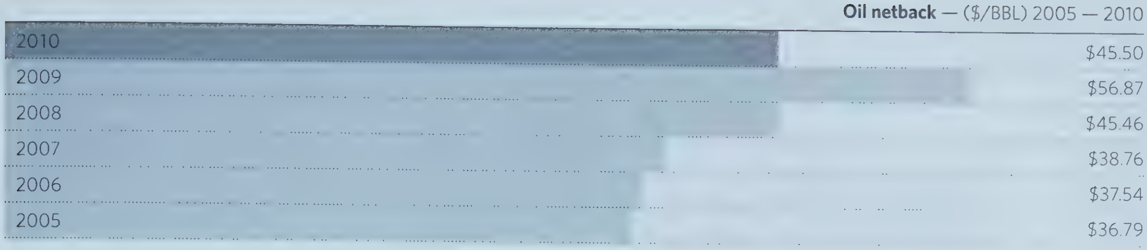
Higher revenue in 2010 was primarily a result of higher production levels. The combined average product price received for oil and gas sales, adjusted for realized gains or losses on financial instruments for the year ended December 31, 2010 was $36.00 per BOE ($35.15 per BOE before financial instruments), a decrease of 11% (an increase of 5% before financial instruments) compared to the previous year. For the three months ended December 31, 2010, the average adjusted product price received was $34.21 per BOE ($33.17 per BOE before financial instruments), down 19% (down 12% before financial instruments) from the average price received in the fourth quarter of 2009.

OIL OPERATIONS

Oil production for the year ended December 31, 2010 averaged 4,070 bbls per day, an increase of 10% compared to the previous year. For the three months ended December 31, 2010, average oil production was 4,096 bbls per day, down 7% from the fourth quarter of 2009. Increased oil production in 2010 reflects the addition of NGLs from the increased liquids-rich natural gas production at Kaybob, Alberta, which more than offset oil asset dispositions during the year.

The average price received for oil sales, after realized financial instruments, for the year ended December 31, 2010 was $67.80 ($67.38 before financial instruments) per barrel, down 16% (up 19% before financial instruments) from the average price

Oil netback — ($/BBL) 2005 — 2010



of $81.00 ($56.45 before financial instruments) per barrel received in 2009. The Company recorded a realized gain of $0.6 million on financial instruments relating to oil price transactions in 2010 compared to a realized gain of $33.0 million in the previous year. The average price received for oil sales, after realized financial instruments, for the fourth quarter ended December 31, 2010 was $68.56 ($66.92 before financial instruments) per barrel, down 15% (up 4% before financial instruments) from the average price of $80.22 ($64.46 before financial instruments) per barrel received in the fourth quarter of 2009.

For the twelve months ended December 31, 2010, average oil royalties were 18.0% of revenue, after financial instruments (18.1% of revenue, before financial instruments). In the previous year, average oil royalties were 13.3% of revenue, after financial instruments (19.0% of revenue, before financial instruments). Lower royalty rates, before financial instruments, in 2010 were a result of lower rates on NGLs as the Company took advantage of Alberta's incentives on new liquids-rich gas horizontal wells drilled and brought on-stream during the year. For the quarter ended December 31, 2010, average oil royalties were 19.1% of revenue, after financial instruments (19.5% of revenue, before financial instruments). In the fourth quarter of the previous year, average oil royalties were 11.1% of revenue, after financial instruments (13.9% of revenue, before financial instruments). Fourth quarter royalty rates, before financial instruments, were lower in 2009 due to gas cost allowance credit adjustments recognized in the quarter.

Transportation expenses for oil production in 2010 averaged $0.18 per barrel compared to $0.27 per barrel in 2009. Lower per unit transportation expenses in 2010 reflect the larger portion of newer NGL production which is mostly pipeline connected and therefore less expensive to transport compared to trucking crude oil. Transportation expenses for oil production in the fourth quarter of 2010 averaged $0.09 per barrel compared to $0.25 per barrel in the fourth quarter of 2009.

For the year ended December 31, 2010, production expenses were $9.94 per barrel, a 24% reduction from the previous year's $13.11 per barrel. During the fourth quarter of 2010, production expenses averaged $7.61 per barrel compared to $12.37 per barrel in the fourth quarter of 2009. Lower per barrel production expenses in 2010 compared to the previous year are a result of the larger component of newly added NGLs included in oil production which are less costly to produce than Celtic's 2009 oil production mix. In addition, oil dispositions in 2010 were in areas that had higher per unit expenses than the rest of Celtic's oil production base.

The breakdown of oil netbacks for 2010 and 2009 are summarized in the following table:

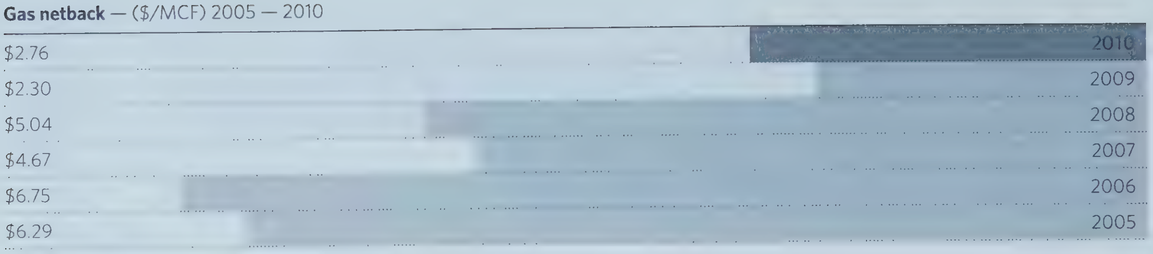
OIL NETBACK	Year ended December 31, 2010		Year ended December 31, 2009		Percent Change
	bbls/d	$/bbl	bbls/d	$/bbl	
Daily average production	**4,070**		**3,687**		10%
Sales price		67.38		56.45	19%
Gain on financial instruments		0.42		24.55	-
Royalties		(12.18)		(10.75)	13%
Production expense		(9.94)		(13.11)	-24%
Transportation expense		(0.18)		(0.27)	-33%
Oil netback		**45.50**		**56.87**	**-20%**

GAS OPERATIONS

Gas production for the year ended December 31, 2010 averaged 79,404 mcf per day, an increase of 26% compared to 63,028 mcf per day in the previous year. Increases in gas production in 2010 were primarily a result of Celtic's successful drilling results in its resource development prospect located at Kaybob, Alberta. Gas production for the fourth quarter ended December 31, 2010 averaged 79,731 mcf per day, an increase of 3% compared to the corresponding period of the previous year.

The average price received for gas sales, after realized financial instruments, for the year ended December 31, 2010 was $4.37 ($4.21 before financial instruments) per mcf, relatively unchanged from the average price of $4.36 ($4.20 before financial

Gas netback — ($/MCF) 2005 — 2010



instruments) per mcf received in 2009. The Company recorded a realized gain of $4.7 million on financial instruments relating to gas price transactions in 2010 compared to a realized gain of $3.7 million in the previous year. The average price received for gas sales, after realized financial instruments, for the fourth quarter ended December 31, 2010 was $3.93 ($3.79 before financial instruments) per mcf, down 19% (down 21% before financial instruments) from the average price of $4.86 ($4.79 before financial instruments) per mcf received in the fourth quarter of 2009.

For the year ended December 31, 2010, average gas royalties were 5.9% of revenue, after financial instruments (6.2% of sales, before financial instruments). In the previous year, average natural gas royalties were 8.5% of revenue, after financial instruments (8.8% of sales, before financial instruments). Actual Crown natural gas royalties payable are determined based on an Alberta reference price and not on actual corporate realized prices. For the quarter ended December 31, 2010, average natural gas royalties were 1.8% of revenue, after financial instruments (2.0% of sales, before financial instruments). In the fourth quarter of the previous year, average natural gas royalties were 4.3% of revenue, after financial instruments (4.4% of sales, before financial instruments). Lower royalties in 2010 compared to the previous year reflect Alberta's royalty incentives of which the majority of Celtic's wells drilled in 2010 qualified for. In addition, royalties are reduced further as the Company continues to receive gas cost allowance ("GCA") credits which do not fluctuate with gas prices.

Transportation expenses for the year ended December 31, 2010 were $0.09 per mcf, a decrease of 40% compared to $0.15 per mcf for the previous year. Transportation expenses for the fourth quarter ended December 31, 2010 were $0.07 per mcf, a decrease of 56% compared to $0.16 per mcf for the same period in the previous year. Lower transportation expenses in 2010 reflect the increase in gas production that is transported on Company owned pipeline infrastructure.

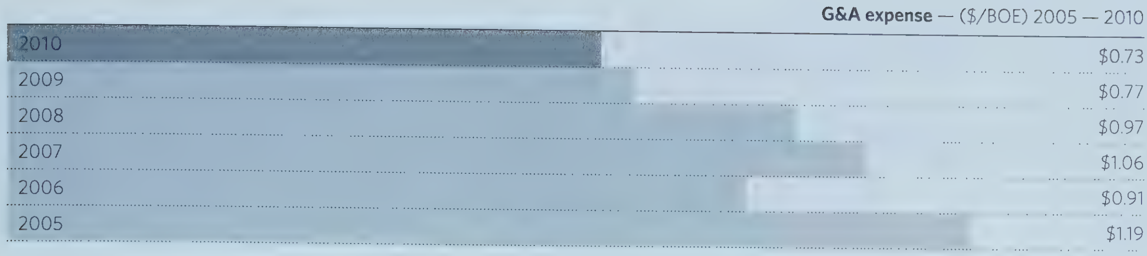
For the twelve months ended December 31, 2010, production expenses of $1.26 per mcf were 18% lower than $1.54 per mcf in the previous year. Higher production expenses in 2009 reflect the additional expenses incurred at Kaybob where a significant amount of the Company's production is processed through the KA Gas Plant. This plant was down for approximately five weeks in the second quarter of 2009 for turnaround operations that occur every four years. For the fourth quarter ended December 31, 2010, production expenses were $1.02 per mcf compared to $1.48 per mcf in the fourth quarter of 2009. Lower production expenses in the fourth quarter of 2010 compared to the same period in the previous year reflect operating and facility improvements at the KA Gas Plant where a significant portion of the Company's gas production is processed.

The breakdown of natural gas netbacks are summarized in the following table:

GAS NETBACK	Year ended December 31, 2010		Year ended December 31, 2009		Percent Change
	mcf/d	$/mcf	mcf/d	$/mcf	
Daily average production	**79,404**		**63,028**		26%
Sales price		4.21		4.20	0%
Gain (loss) on financial instruments		0.16		0.16	-
Royalties		(0.26)		(0.37)	-30%
Production expense		(1.26)		(1.54)	-18%
Transportation expense		(0.09)		(0.15)	-40%
Natural gas netback		**2.76**		**2.30**	**20%**

INTEREST EXPENSE

Celtic has a committed term credit facility with a syndicate of financial institutions, led by National Bank of Canada and including HSBC Bank Canada, Canadian Western Bank, Royal Bank of Canada and BNP Paribas (Canada). The authorized borrowing amount under this facility is $215.0 million. The facilities are available for a period of 364 days, maturing on June 28, 2011. Repayments of principal are not required provided that the borrowings under the facility do not exceed the authorized borrowing amount and the Company is in compliance with all covenants, representations and warranties. Covenants include a current ratio test, reporting



requirements, permitted indebtedness, permitted dispositions, permitted hedging, permitted encumbrances and other standard business operating covenants. The authorized borrowing amount is subject to interim reviews by the financial institutions. Security is provided for by a first fixed and floating charge debenture over all assets in the amount of $500.0 million and general assignment of book debts.

Interest is payable monthly for borrowings through direct advances. Interest rates fluctuate based on a pricing grid and range from bank prime plus 1.25% to bank prime plus 3.25%, depending upon the Company's then current debt to cash flow ratio of between less than one and one tenth times to equal to or greater than three times. Under the credit facility, borrowings through the use of bankers' acceptances are also available. Stamping fees fluctuate based on a pricing grid and range from 2.25% to 4.25%, depending upon the Company's then current debt to cash flow ratio of between less than one and one tenth times to equal to or greater than three times.

The Company has entered into interest rate swap transactions whereby borrowings through bankers' acceptances in the amount of $100.0 million maturing on April 21, 2011 has been fixed at an annual interest rate of 2.1% from April 22, 2010 to April 21, 2011, before bank stamping fees.

Interest expense for the year, before financial instruments, was $5.9 million at an average rate of 4.1% compared to $5.0 million at an average rate of 3.3% in 2009.

INTEREST EXPENSE	Year ended December 31, 2010	Year ended December 31, 2009	Percent Change
	$ thousands	$ thousands	
Interest expense	5,853	5,025	16%
Average bank debt outstanding	144,444	151,410	-5%
Average interest rate *(%)*	**4.1%**	**3.3%**	**24%**

The Company recorded a realized loss of $1.7 million on financial instruments relating to interest rate swap transactions in 2010 compared to a realized loss of $2.4 million in the previous year.

GENERAL AND ADMINISTRATIVE EXPENSES

General and administrative ("G&A") expenses for the year ended December 31, 2010 were $4.6 million or $0.73 per BOE compared to $3.9 million or $0.77 per BOE in 2009. G&A expenses are reduced by overhead recovered on Company operated properties. In addition, salaries relating to geological and geophysical personnel are capitalized.

The following table provides a breakdown of G&A expenses:

GENERAL AND ADMINISTRATIVE EXPENSES	Year ended December 31, 2010		Year ended December 31, 2009		Percent Change	
	$ thousands	$/BOE	$ thousands	$/BOE	$ thousands	$/BOE
Gross G&A expenses	8,884	1.41	8,012	1.55	11%	-9%
Overhead recoveries	(3,846)	(0.61)	(3,639)	(0.70)	6%	-13%
Capitalized overhead	(426)	(0.07)	(426)	(0.08)	0%	-13%
G&A expenses	**4,612**	**0.73**	**3,947**	**0.77**	**17%**	**-5%**

EMPLOYEES	At December 31, 2010	At December 31, 2009	Percent Change
Head office	40	39	3%
Field operations	16	13	23%
Total Employees	**56**	**52**	**8%**

DD&A expense — ($/BOE) 2005 — 2010

Celtic continues to operate with low G&A expense per BOE compared to many of its peers and is able to do so primarily due to the fact that the Company's operations are geographically focused and concentrated with the majority of its production coming from the Greater Kaybob area of Alberta.

STOCK BASED COMPENSATION EXPENSE

Stock based compensation expense is a non-cash charge which reflects the value of stock options awarded to directors, employees and certain consultants. The value is recognized as an expense over the period from the grant date to the date of vesting of the award.

For the year ended December 31, 2010, stock based compensation expense was $3.3 million, compared to $2.4 million in 2009.

The fair value of each option granted is estimated on the date of grant using the Black-Scholes option pricing model with weighted average assumptions shown in the following table:

STOCK BASED COMPENSATION EXPENSE	Year ended December 31, 2010		Year ended December 31, 2009		Percent Change	
	$ thousands	$/BOE	$ thousands	$/BOE	$ thousands	$/BOE
Stock based compensation expense	**3,262**	**0.52**	**2,362**	**0.46**	**38%**	**13%**
Weighted average assumptions for stock options granted:						
Risk-free interest rate	0.54%		0.50%		8%	
Expected life in years	3.0		3.0		0%	
Expected volatility	40%		30%		33%	
Expected dividend yield	-		-		-	

On a barrel of oil equivalent basis, stock based compensation expense was $0.52 per BOE in 2010, up from $0.46 per BOE in 2009.

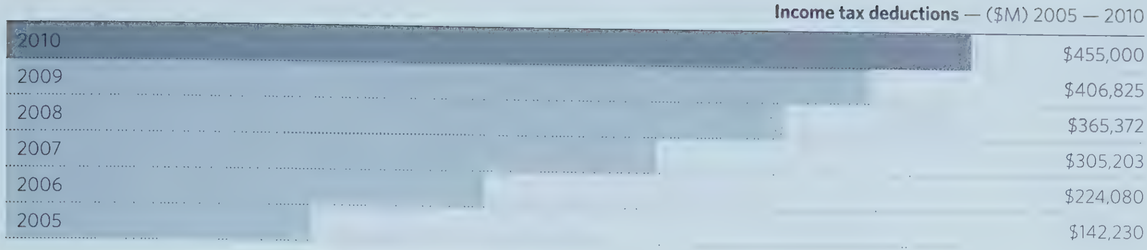
LOSS ON DISPUTED PROCESSING FEES

Celtic and SemCAMS were parties to a confidential KA Plant Inlet Gas Purchase Agreement (the "KA Plant IGPA"). SemCAMS entered into proceedings under CCAA on July 21, 2008. Celtic and SemCAMS were in disagreement with respect to whether the terms under the KA Plant IGPA should have remained in force subsequent to July 21, 2008. The courts ruled in favour of SemCAMS with respect to disputed processing fee charges from July 22, 2008 to November 30, 2009. As a result, Celtic has recorded a loss on disputed processing fees in the amount of $4.7 million in 2010.

DEPLETION, DEPRECIATION AND ACCRETION

The Company follows the full cost method of accounting whereby all costs relating to the exploration and development of oil and gas reserves are capitalized. These capitalized costs along with estimated future development capital expenditures to be incurred in order to develop proved reserves, are depleted on a unit of production basis using estimated proved oil and gas reserves. Depreciation of furniture and office equipment is provided using the declining balance method at a rate of 25%. Estimated future costs relating to asset retirement obligations are provided for on a unit of production basis, and the provision is included in depletion, depreciation and accretion ("DD&A").

DD&A expense for the period ended December 31, 2010 was $114.7 million or $18.17 per BOE, compared to the previous year's amount of $101.8 million or $19.65 per BOE.



The following table provides a summary of the amounts included in DD&A:

DEPLETION, DEPRECIATION AND ACCRETION	Year ended December 31, 2010		Year ended December 31, 2009		Percent Change	
	$ thousands	$/BOE	$ thousands	$/BOE	$ thousands	$/BOE
Depletion - intangible oil and gas assets	88,412	14.00	76,873	14.84	15%	-6%
Depreciation - tangible oil and gas assets	24,827	3.93	23,586	4.55	5%	-14%
Depreciation - furniture and office equipment	260	0.04	213	0.04	22%	0%
Amortization - asset retirement costs	878	0.14	616	0.12	43%	17%
Accretion of asset retirement obligation	372	0.06	520	0.10	-28%	-40%
Depletion, depreciation and accretion	**114,749**	**18.17**	**101,808**	**19.65**	**13%**	**-8%**

CEILING TEST

The Company performed a ceiling test calculation at December 31, 2010 in accordance with the CICA full cost accounting guidelines. As a result of the calculation, Celtic was not required to record an impairment loss. In addition, based on the calculation in the previous year conducted at December 31, 2009, there was no impairment loss required.

The forecasted future oil and gas prices for the next five years used in the ceiling test evaluation of the Company's proved reserves as at December 31, 2010 were as follows:

FORECAST PRICES	2011	2012	2013	2014	2015
Oil *($/bbl)*	$ 85.40	$ 86.81	$ 85.00	$ 84.36	$ 85.38
NGLs *($/bbl)*	73.22	74.56	74.69	74.93	76.18
Natural gas *($/mcf)*	4.13	4.78	5.14	6.85	6.97

Prices escalate at varying percentages in a range between 1.0% and 1.8% thereafter.

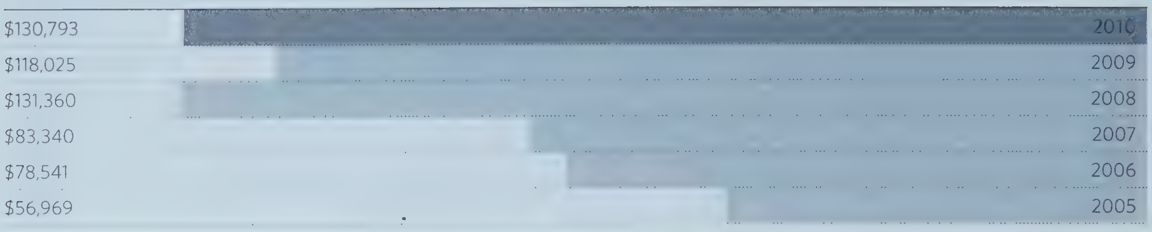
TAXES

In 2010, Celtic recorded a provision for income taxes in the amount of $3.9 million and in 2009, Celtic provided for a recovery of future income taxes in the amount of $9.6 million. These amounts differ from the expected provision for (recovery of) income taxes based on the statutory combined income tax rate of 28.0% in 2010 and 29.0% in 2009 due to the differences between non-deductible stock based compensation expense and the recognition of a benefit primarily relating to substantively enacted changes to future federal and provincial income tax rates. An analysis of the income tax provision is included in the notes to the financial statements.

At December 31, 2010, Celtic had estimated unused income tax deductions available of approximately $455.0 million. A summary of these deductions with corresponding rates of deductibility is shown in the table below:

INCOME TAX DEDUCTIONS	At December 31, 2010		At December 31, 2009		Percent Change
	$ thousands	deduction rate	$ thousands	deduction rate	
Canadian oil and gas property expense (COGPE)	82,000	10%	97,800	10%	-16%
Canadian development expense (CDE)	201,000	30%	152,302	30%	32%
Canadian exploration expense (CEE)	67,000	100%	44,364	100%	51%
Undepreciated capital cost (UCC)	103,000	4% to 30%	107,790	4% to 30%	-4%
Share issue costs	2,000	5 years	4,569	5 years	-56%
Income tax deductions	**455,000**		**406,825**		**12%**

Funds from operations — ($M) 2005 — 2010



FUNDS FROM OPERATIONS AND CASH PROVIDED BY OPERATING ACTIVITIES

Funds from operations is a non-GAAP measure defined as cash provided by operating activities before changes in non-cash operating working capital and settlement of asset retirement obligations. Despite being a non-GAAP measure, funds from operations is commonly used in the oil and gas industry and by Celtic to assist in measuring the Company's ability to finance capital programs and meet financial obligations.

Funds from operations for the year ended December 31, 2010 was $130.8 million ($1.46 per share, basic and $1.43 per share, diluted). In 2009, funds from operations were $118.0 million ($1.36 per share, basic and $1.35 per share, diluted). Funds from operations for the three months ended December 31, 2010 was $30.6 million ($0.34 per share, basic and $0.33 per share, diluted). In the fourth quarter of 2009, funds from operations were $42.0 million ($0.47 per share, basic and $0.46 per share, diluted).

On a barrel of oil equivalent basis, funds from operations in 2010 were $20.73 per BOE, down 9% from $22.78 per BOE in 2009. Despite improvements in per unit expenses, funds from operations per BOE were lower in 2010 due to the significant gain on financial instruments recorded in 2009. On a barrel of oil equivalent basis, funds from operations in the fourth quarter of 2010 were $19.15 per BOE, down 28% from $26.44 per BOE in the fourth quarter of 2009. The decrease in the fourth quarter of 2010 compared to the same period in 2009 was attributable to lower commodity prices, lower gains on financial instruments and a loss on disputed processing fees that was recorded in the fourth quarter of 2010.

The following table provides a reconciliation of funds from operations for the past two years:

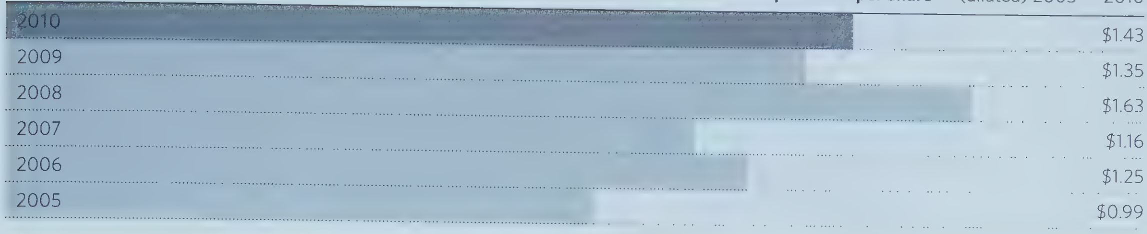
FUNDS FROM OPERATIONS *($ thousands)*	Year ended December 31, 2010	Year ended December 31, 2009	Percent Change
Cash provided by operating activities	**154,993**	**103,721**	**49%**
Settlement of asset retirement obligations	1,897	1,043	82%
Change in non-cash operating working capital	(26,097)	13,261	-
Funds from operations	**130,793**	**118,025**	**11%**

Cash provided by operating activities for the year ended December 31, 2010 was $155.0 million, up 49% from $103.7 million in 2009. Cash provided by operating activities for the three months ended December 31, 2010 was $38.2 million, up 9% from $33.9 million in the fourth quarter of 2009.

NET EARNINGS

Net earnings for the year ended December 31, 2010 was $6.6 million ($0.07 per share, basic and diluted). Net loss for the year ended December 31, 2009 was $23.3 million ($0.27 per share, basic and diluted). Net loss for the three months ended December 31, 2010 was $3.0 million ($0.03 per share, basic and diluted). Net earnings for the fourth quarter of 2009 was $0.9 million ($0.01 per share, basic and diluted).

Funds from operations per share — (diluted) 2005 — 2010



The following table provides detailed unit statistics on a barrel of oil equivalent basis:

UNIT STATISTICS	Year ended December 31, 2010		Year ended December 31, 2009		Percent Change
	BOE/d	$/BOE	BOE/d	$/BOE	
Daily average production	**17,304**		**14,192**		**22%**
Sales price		35.15		33.33	5%
Gain (loss) on financial instruments		0.85		7.10	-88%
Royalties		(4.05)		(4.43)	-9%
Production expense		(8.13)		(10.26)	-21%
Transportation expense		(0.44)		(0.74)	-41%
Operating netback		**23.38**		**25.00**	**-6%**
General and administrative expense		(0.73)		(0.76)	-4%
Interest expense, including financial instruments		(1.18)		(1.46)	-19%
Contingency loss		(0.74)		-	-
Funds from operations		**20.73**		**22.78**	**-9%**
Unrealized gain (loss) on financial instruments		(0.37)		(6.47)	-94%
Stock based compensation expense		(0.52)		(0.46)	13%
Depletion, depreciation and accretion		(18.17)		(19.65)	-8%
Provision for non-recoverable accounts receivable		-		(2.55)	-
Future income tax		(0.61)		1.86	-
Net earnings (loss)		**1.06**		**(4.49)**	**-**

INVESTMENT AND INVESTMENT EFFICIENCIES

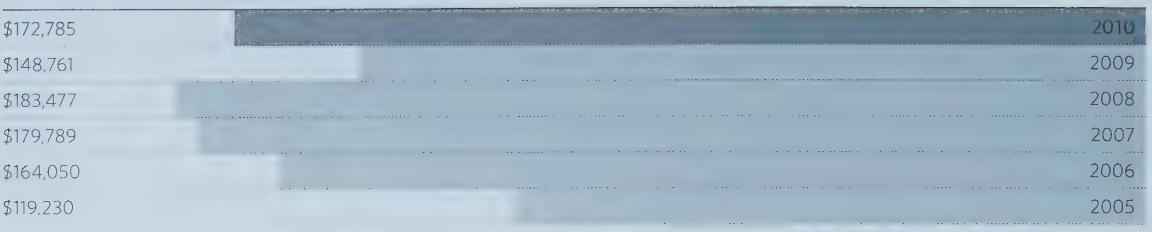
CAPITAL EXPENDITURES

Celtic is committed to future growth through its strategy to implement a full cycle exploration and development program, augmented by strategic acquisitions with exploitation upside.

During the year ended December 31, 2010, Celtic incurred $229.7 million on exploration and development activity, $7.7 million on property acquisitions and recorded net proceeds of $64.6 million from property dispositions. Drilling and completion operations accounted for $155.7 million and the Company earned $1.3 million in drilling royalty credits that are eligible to be claimed against corporate crown royalties payable. Equipment and facility expenditures were $37.9 million. The balance of $37.4 million was spent on land and seismic, thereby building the Company's inventory of prospects for future drilling opportunities. Approximately 86% of net wells drilled were categorized as development and 14% were exploratory.

During the year ended December 31, 2009, Celtic incurred $147.0 million on exploration and development activity, $2.2 million on property acquisitions and recorded net proceeds of $0.4 million from property dispositions. Drilling and completion operations accounted for $125.3 million and the Company earned $20.6 million in drilling royalty credits that are eligible to be claimed against corporate crown royalties payable. Equipment and facility expenditures were $32.1 million. The balance of $10.2 million was spent on land and seismic, building the Company's inventory of prospects for future drilling opportunities. Approximately 96% of net wells drilled were categorized as development and 4% were exploratory.

Capital expenditures, net — ($M) 2005 — 2010



The Company's capital expenditures, including acquisitions and dispositions, for 2010 and 2009 are summarized in the following table:

CAPITAL EXPENDITURES	Year ended December 31, 2010		Year ended December 31, 2009		Percent Change
	$ thousands	% of total	$ thousands	% of total	
Property, plant and equipment expenditures					
Lease acquisitions and retention	36,667	21%	9,464	6%	287%
Geological and geophysical activity	684	0%	714	0%	-4%
Drilling and completion of wells	155,719	91%	125,257	86%	24%
Drilling royalty credits	(1,281)	-1%	(20,619)	-14%	-
Facilities, pipeline and well equipment	37,369	22%	31,896	21%	17%
Head office and computers	551	0%	252	0%	119%
	229,709	133%	146,964	99%	56%
Property, plant and equipment acquisitions	7,703	4%	2,172	1%	255%
Property, plant and equipment dispositions	(64,627)	-37%	(375)	0%	17,134%
Corporate acquisitions	-	0%	-	0%	-
Capital expenditures, net	**172,785**	**100%**	**148,761**	**100%**	**16%**

LAND HOLDINGS

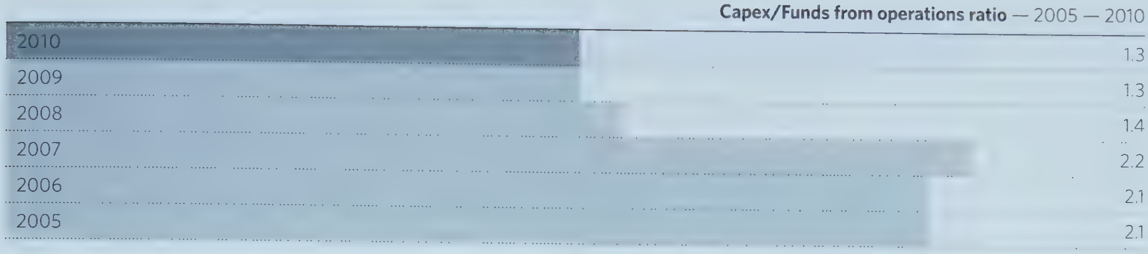
As at December 31, 2010, Celtic owned 621,199 net acres of undeveloped land, representing a 111% increase compared to 294,700 net acres at the end of 2009. Based on an internal evaluation of the fair market value of its land holdings at December 31, 2010, Celtic estimates the fair market value of its undeveloped land at $ 417.6 million. Included in Celtic's estimate of fair market value is an estimate for its undeveloped Duvernay rights in the greater Kaybob area. The majority of these Duvernay rights are contained within the same land tenure documents that overlay productive petroleum and natural gas rights and, as such, are not technically defined as undeveloped lands. Celtic owns 101,630 gross acres and 88,226 net acres of undeveloped Duvernay rights in the greater Kaybob area, with an estimated fair market value of $ 152.5 million.

Approximately 8% of net undeveloped land holdings will be subject to expiry in 2011, if not developed. Celtic holds an average 91% working interest in its undeveloped lands.

Celtic took full advantage of prolonged weak natural gas prices and an overall downturn in the industry in 2010 and aggressively built its prospect inventory via Crown land sales at an attractive cost structure. In 2010, Celtic expended approximately $35.6 million at Alberta Crown land sales acquiring 379,310 net acres of petroleum and natural gas rights at an average bonus cost of $94 per acre; compared to an industry average of $246 per acre. By way of comparison, in 2009 Celtic spent $8.3 million acquiring 74,170 net acres at an average cost of $112 per acre. The year 2010 represented the most active year for the Company for acquiring petroleum and natural gas rights at Crown land sales.

The vast majority of the Company's 2010 land sale activity was focused on aggressively expanding its new core area at Resthaven, Lator and Karr (collectively referred to as the "Resthaven area") in west central Alberta. Celtic actively commenced acquiring a land position in 2009 (approximately 37,000 net acres); and in 2010 the Company significantly added to its land position in the Resthaven area. As at December 31, 2010, the Company owned 383,051 gross acres (598 sections) and 381,771 net acres (596 sections) of Triassic Montney rights in the Resthaven area.

Capex/Funds from operations ratio — 2005 — 2010



The following table summarizes Celtic's land holdings as at December 31, 2010 and 2009:

LAND HOLDINGS	As at December 31, 2010		As at December 31, 2009		Percent Change	
(Acres)	Gross	Net	Gross	Net	Gross	Net
Developed	194,942	109,218	204,795	117,954	-5%	-7%
Undeveloped	685,993	621,199	363,473	294,700	89%	111%
Total	**880,935**	**730,417**	**568,268**	**412,654**	**55%**	**77%**
Average working interest		**83%**		**73%**		

Celtic's ongoing land acquisition strategy is focused on building a significant land base of high working interest, internally generated prospects; complemented by third party farm-in arrangements in core exploration areas. The Company will continue building a significant base of high working interest operated prospects, ensuring that the Company is in a position to control its capital expenditure program.

DRILLING

Celtic's drilling operations continued to remain active in 2010. During the year ended December 31, 2010, Celtic drilled 62 (41.9 net) wells, with an overall success rate of 90% on net wells drilled. The Company's average working interest in wells drilled during 2010 was 68%. The split between development drilling and exploratory drilling was 86% and 14%, respectively. In 2010, Celtic's active horizontal drilling program resulted in an average measured depth of net wells drilled of 3,514 metres. The Company drilled a total of 147,175 net metres during the year.

In the previous year ended December 31, 2009, Celtic drilled 55 (43.0 net) wells, with an overall success rate of 91% on net wells drilled. The Company's average working interest in wells drilled during 2009 was 78%. The split between development drilling and exploratory drilling was 96% and 4%, respectively. In 2009, the average measured depth of net wells drilled was 3,289 metres. The Company drilled a total of 141,409 net metres during the year.

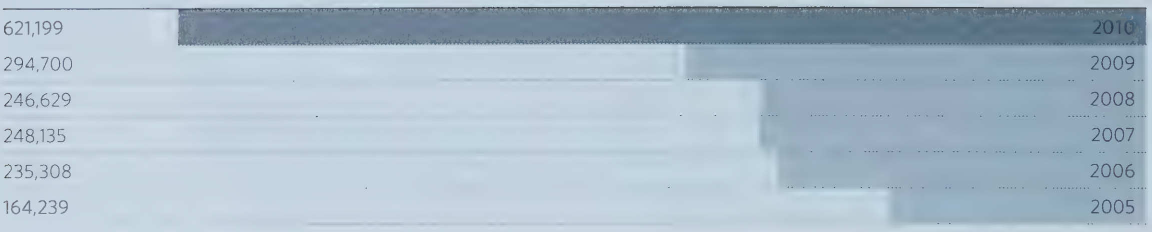
The following table summarizes Celtic's drilling activity in 2010:

DRILLING ACTIVITY	Development Wells		Exploration Wells		Total Wells	
Year ended December 31, 2010	Gross	Net	Gross	Net	Gross	Net
Natural gas	48	29.5	6	4.8	54	34.3
Coal bed methane	2	1.6	0	0.0	2	1.6
Oil	2	2.0	0	0.0	2	2.0
Dry	3	3.0	1	1.0	4	4.0
Total wells	**55**	**36.1**	**7**	**5.8**	**62**	**41.9**
Success rate, based on net wells		**92%**		**83%**		**90%**

RESERVES

Celtic retains Sproule Associates Limited ("Sproule"), an independent qualified reserve evaluator to prepare a report on 100% of its oil and gas reserves. The Company has a Reserves Committee which oversees the selection, qualifications and reporting procedures of the independent engineering consultants. Reserves as at December 31, 2010 were determined using the guidelines and definitions set out under National Instrument 51-101 ("NI 51-101").

Undeveloped land — (net acres) 2005 — 2010



At December 31, 2010, Celtic's proved plus probable reserves were 67.5 million BOE, up 12% from 60.4 million BOE at the end of 2009. The Company's net present value of proved plus probable reserves at December 31, 2010, discounted at 10% before tax, was $930.7 million, down 8% from $1,011.9 million at December 31, 2009. Despite a 12% increase in reserves, the net present value was lower compared to the previous year primarily due to lower future natural gas prices used in the December 31, 2010 evaluation. In addition, the Company completed non-core asset dispositions of 2.3 million BOE of proved plus probable reserves during 2010.

The reserve life index for proved plus probable reserves was 10.5 years compared to 9.6 years at December 31, 2009. At December 31, 2010, the weighting of proved plus probable reserves was 25% oil and 75% gas.

The following table outlines a summary of the Company's reserves at December 31, 2010:

SUMMARY OF RESERVES As at December 31, 2010	Oil mbbls	Gas mmcf	Combined mBOE	FDC Costs $ thousands
Proved Developed Producing	6,326	108,776	24,455	
Proved Developed Non-producing	743	11,813	2,712	
Proved Undeveloped	2,381	54,615	11,484	
Total Proved	**9,450**	**175,204**	**38,651**	**$ 131,317**
Probable Additional	7,356	128,993	28,855	
Total Proved plus Probable	**16,806**	**304,197**	**67,506**	**$ 209,719**

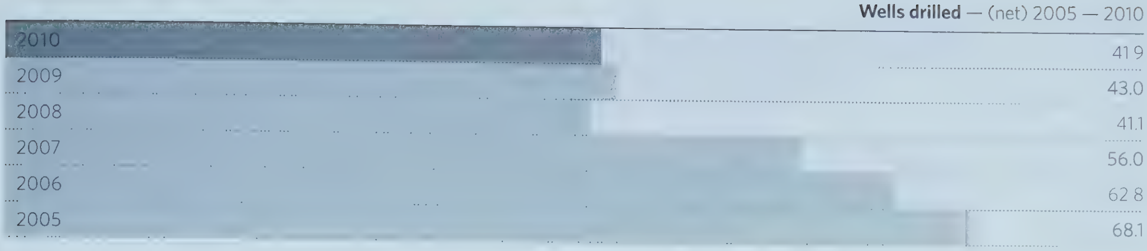
Future development capital ("FDC") expenditures included in the reserve evaluation have been reduced by drilling royalty credits ("DRC's") earned and expected to be claimed in the first quarter of 2011. FDC included in the total proved reserve evaluation is expected to be spent as follows: $100.9 million in 2011, $17.7 million in 2012 and $12.7 million in 2013 and thereafter. FDC included in the proved plus probable reserve evaluation is expected to be spent as follows: $144.2 million in 2011, $50.3 million in 2012 and $15.2 million in 2013 and thereafter.

The following table outlines the change in the Company's reserves year-over-year:

RESERVES RECONCILIATION	Oil		Gas		Combined	
	Total Proved mbbls	Proved + Probable mbbls	Total Proved mmcf	Proved + Probable mmcf	Total Proved mBOE	Proved + Probable mBOE
Balance, December 31, 2009	**8,856**	**15,042**	**159,592**	**272,236**	**35,455**	**60,415**
Discoveries	372	548	6,271	9,034	1,417	2,054
Extensions	1,188	3,360	20,872	55,896	4,667	12,676
Infill Drilling	535	1,113	13,141	24,026	2,725	5,117
Technical Revisions	989	(145)	4,278	(29,093)	1,702	(4,994)
Economic Factors	(93)	(141)	(2,129)	(2,539)	(448)	(564)
Acquisitions	339	587	2,910	5,015	824	1,423
Dispositions	(1,250)	(2,072)	(749)	(1,396)	(1,375)	(2,305)
Net Additions	**2,080**	**3,250**	**44,594**	**60,943**	**9,512**	**13,407**
Production	(1,486)	(1,486)	(28,982)	(28,982)	(6,316)	(6,316)
Balance, December 31, 2010	**9,450**	**16,806**	**175,204**	**304,197**	**38,651**	**67,506**
Percentage Increase in Reserves	**7%**	**12%**	**10%**	**12%**	**9%**	**12%**

In aggregate, Celtic's technical revisions are positive 4.8% for proved reserves and negative 8.3% for proved plus probable reserves on a BOE basis.

Wells drilled — (net) 2005 — 2010



The following table outlines forecasted future prices that Sproule has used in their evaluation of the Company's reserves at December 31, 2010:

FUTURE COMMODITY PRICE FORECAST	WTI Cushing Crude Oil US$/bbl	NYMEX HH Natural Gas US$/mmbtu	AECO-C Natural Gas $/GJ	USD/CAD Exchange US$
2011	88.40	4.44	3.83	0.932
2012	89.14	5.01	4.42	0.932
2013	88.77	5.32	4.73	0.932
2014	88.88	6.80	6.24	0.932
2015	90.22	6.90	6.34	0.932
Five Year Average	**89.08**	**5.69**	**5.11**	**0.932**

The average price of oil steadily increased in each of the years from 2005 to 2008; however, in 2009 oil prices were considerably lower than the previous year. In 2010, WTI oil prices recovered and averaged US$79.43 per bbl, up from US$61.63 per bbl in 2009. Average annual natural gas prices at AECO-C from 2005 to 2008 traded in a range from $6.31 to $8.14 per GJ; however, in 2009, AECO-C averaged a much lower price of $3.97 per GJ and continued at this level averaging $3.94 per GJ in 2010.

Sproule is forecasting WTI oil prices to average US$89.08 per bbl over the next five years, 3% higher than the average price of US$86.55 per bbl over the past five years. For natural gas, AECO-C natural gas prices are forecasted to average $5.11 per GJ over the 2011 to 2015 period, a decrease of 19% from the average price of $6.30 per GJ during the 2006 to 2010 period.

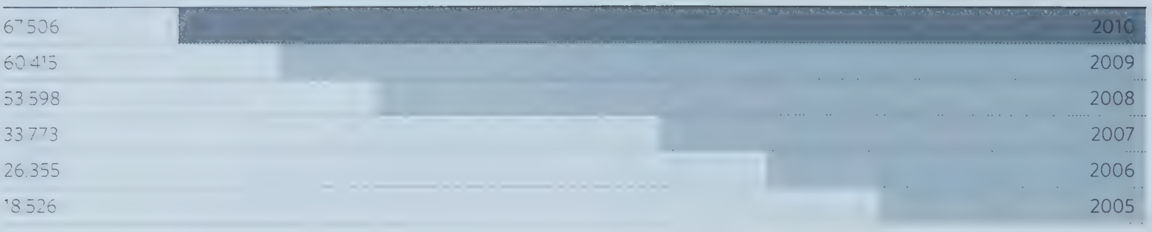
The following table is a net present value summary (before tax) as at December 31, 2010:

NET PRESENT VALUE SUMMARY (BEFORE TAX) *($ thousands)*	Undiscounted	NPV 5% BT	NPV 10% BT	NPV 15% BT
Proved Developed Producing	611,593	492,560	417,036	364,530
Proved Developed Non-producing	61,397	51,291	44,015	38,542
Proved Undeveloped	209,767	149,212	110,277	83,249
Total Proved	**882,757**	**693,063**	**571,328**	**486,321**
Probable Additional	796,790	501,413	359,422	276,414
Total Proved plus Probable	**1,679,547**	**1,194,476**	**930,750**	**762,735**

The following table is a net present value summary (after tax) as at December 31, 2010:

NET PRESENT VALUE SUMMARY (AFTER TAX) *($ thousands)*	Undiscounted	NPV 5% AT	NPV 10% AT	NPV 15% AT
Proved Developed Producing	571,867	465,578	397,629	349,990
Proved Developed Non-producing	46,040	38,551	33,201	29,202
Proved Undeveloped	157,143	108,659	77,370	55,641
Total Proved	**775,051**	**612,788**	**508,200**	**434,833**
Probable Additional	596,942	373,961	266,417	203,471
Total Proved plus Probable	**1,371,993**	**986,749**	**774,617**	**638,305**

Reserves — (MBOE) 2005 — 2010



The Company's net present value of proved plus probable reserves, discounted at 10% before tax was $930.7 million, down 14% from $1,011.9 million at December 31, 2009. As mentioned above, lower forecasted natural gas prices negatively affected the value of reserves as at December 31, 2010. In addition, during 2010, the Company disposed of 2.3 million BOE of proved plus probable reserves relating to non-core assets. Production relating to properties disposed in 2010 was approximately 650 BOE per day.

The following table provides detailed calculations relating to finding, development and acquisition ("FD&A") costs and recycle ratios for 2010 and 2009:

FINDING, DEVELOPMENT & ACQUISITION COSTS	Year ended December 31, 2010	Year ended December 31, 2009	Cumulative since Incorporation
Proved Reserves			
Capital expenditures *($ thousands)*	**172,785**	148,761	1,109,420
Change in FDC costs required to develop reserves *($ thousands)*	**40,844**	(1,483)	131,317
Total capital costs *($ thousands)*	**213,629**	147,278	1,240,737
Reserve additions, net *(mBOE)*	**9,512**	11,426	62,665
FD&A cost, before FDC *($/BOE)*	**18.16**	13.02	17.70
FD&A cost, including FDC *($/BOE)*	**22.46**	**12.89**	**19.80**
Operating netback *($/BOE)*	**23.38**	**25.00**	**29.31**
Recycle ratio - proved	**1.0 x**	**1.9 x**	**1.5 x**
P+P Reserves			
Capital expenditures *($ thousands)*	**172,785**	148,761	1,109,420
Change in FDC costs required to develop reserves *($ thousands)*	**64,702**	(30,697)	209,719
Total capital costs *($ thousands)*	**237,487**	118,064	1,319,139
Reserve additions, net *(mBOE)*	**13,407**	11,997	91,363
FD&A cost, before FDC *($/BOE)*	**12.89**	12.40	12.14
FD&A cost, including FDC *($/BOE)*	**17.71**	**9.84**	**14.44**
Operating netback *($/BOE)*	**23.38**	**25.00**	**29.31**
Recycle ratio - proved plus probable	**1.3 x**	**2.5 x**	**2.0 x**

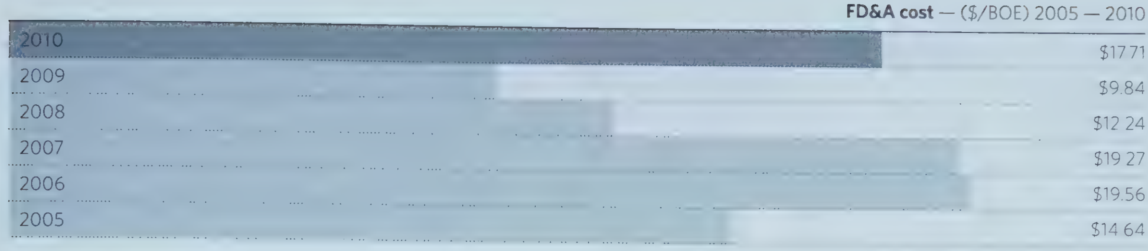
During 2010, the Company's capital expenditures, net of dispositions, resulted in proved plus probable reserve additions of 13.4 million (12.0 million in 2009) BOE, resulting in FD&A costs of $17.71 ($9.84 in 2009) per BOE, including FDC costs. Proved reserve additions in 2010 were 9.5 million (11.4 million in 2009) BOE, resulting in FD&A costs of $22.46 ($12.89 in 2009) per BOE, including FDC costs.

Higher FD&A costs in 2010 compared to the previous year were a result of the Company's strategy to incur significant expenditures in 2010 on land and drilling in two new resource plays: a Montney play at Resthaven, Alberta and a Duvernay play at Kaybob, Alberta. With success in these plays, the Company would have the potential to add significant reserves in 2011 and in the future.

The recycle ratio is a measure for evaluating the effectiveness of a company's re-investment program. The ratio measures the efficiency of capital investment. It accomplishes this by comparing the operating netback per BOE to that years' reserve FD&A cost per BOE. Since incorporation, Celtic has successfully achieved a recycle ratio of 2.0 times on a proved plus probable basis. In 2010, the recycle ratio was 1.3 times.

Celtic's 2010 capital investment program resulted in net reserve additions that replaced 2010 production by a factor of 1.5 (2.2 in 2009) times on a proved basis and 2.1 (2.3 in 2009) times on a proved plus probable basis.

FD&A cost — ($/BOE) 2005 — 2010



The following table summarizes production replacement for 2010:

PRODUCTION REPLACEMENT	Proved			Proved plus Probable		
Year ended December 31, 2010	Oil mbbls	Gas mmcf	Combined mBOE	Oil mbbls	Gas mmcf	Combined mBOE
Reserve additions, including revisions	2,080	44,594	9,512	3,250	60,943	13,407
2010 Production	1,486	28,982	6,316	1,486	28,982	6,316
Production replacement ratio	**1.4**	**1.5**	**1.5**	**2.2**	**2.1**	**2.1**

NET ASSET VALUE

Celtic's net asset value at December 31, 2010 increased to $1,200.1 million, up 27% from $946.1 million at December 31, 2009. On a per share basis, net asset value increased by 25% to $12.32 per share compared to $9.88 per share at December 31, 2009. The present value of petroleum and natural gas ("P&NG") reserves were determined by Sproule in their year-end evaluation report. The present value of P&NG reserves is determined using a discount rate of 10% before tax. Undeveloped land at December 31, 2010 was valued at an average price of $672 per acre compared to $192 per acre at December 31, 2009. Proceeds from exercise of stock options are based on average exercise prices of $8.31 per share at December 31, 2010 and $6.95 per share at December 31, 2009.

The components of net asset value are summarized in the following table:

NET ASSET VALUE *($ thousands)*	At December 31, 2010	At December 31, 2009	Percent Change
Present value of P&NG reserves, discounted at 10% BT	930,750	1,011,939	-8%
Undeveloped land	417,600	56,582	638%
Bank debt, net of working capital	(202,683)	(168,417)	20%
Proceeds from exercise of stock options	54,419	45,967	18%
Net asset value	**1,200,086**	**946,071**	**27%**
Diluted common shares outstanding *(thousands)*	97,425	95,742	2%
Net asset value per share *($/share)*	**12.32**	**9.88**	**25%**

CAPITAL RESOURCES AND LIQUIDITY

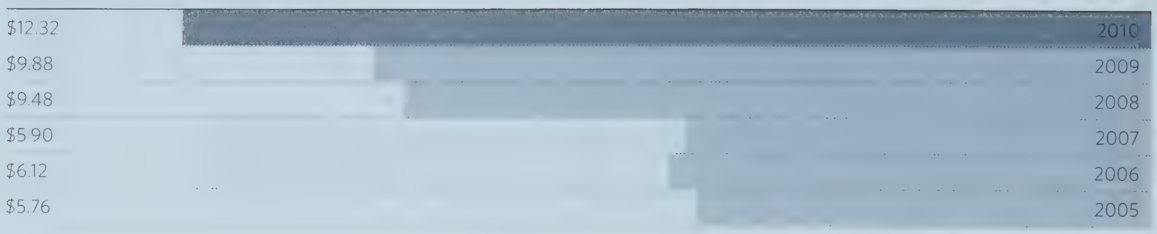
MARKET CAPITALIZATION

The Company's total capitalization increased 63% to $1,874.6 million at December 31, 2010. Market value of common shares represented 85% of total capitalization, while debt, including working capital represented 11% of total capitalization.

The following table summarizes the Company's capitalization:

CAPITALIZATION	At December 31, 2010		At December 31, 2009		
($ thousands, except per share amounts)	$ thousands	ratio	$ thousands	ratio	Percent Change
Common shares outstanding *(thousands)*	90,876		89,126		2%
Share price (last price traded at in the year)	17.72		10.45		70%
Market capitalization	1,610,323	85%	930,921	80%	73%
Bank debt, net of working capital	202,683	11%	168,417	15%	20%
Asset retirement obligation	9,918	1%	6,588	1%	51%
Future income tax liability	51,676	3%	47,203	4%	9%
Total capitalization	**1,874,600**	**100%**	**1,153,129**	**100%**	**63%**

NAV per share — 2005 — 2010



At December 31, 2010, the Company had $160.8 million outstanding on its credit facility. Net debt, including working capital surplus was $202.7 million, representing approximately 1.5 times 2010 funds from operations and approximately 1.3 times forecasted 2011 funds from operations.

KEY DEBT RATIOS	At December 31, 2010		At December 31, 2009		
	$ thousands	ratio	$ thousands	ratio	Percent Change
Debt to funds from operations ratio:					
Total debt	202,683		168,417		20%
Funds from operations	130,793		118,025		11%
Funds from operations - 2011 forecast	159,000				
Debt to funds from operations - trailing		1.5		1.4	7%
Debt to funds from operations - forward		**1.3**		**1.3**	0%
Asset coverage ratio:					
Total assets	723,025		678,770		7%
Total debt	202,683		168,417		20%
Asset coverage		**3.6**		**4.0**	-10%
Debt to equity ratio:					
Total debt	202,683		168,417		20%
Shareholders' equity	408,095		387,190		5%
Debt/equity		**0.5**		**0.4**	25%

SOURCE OF FUNDS

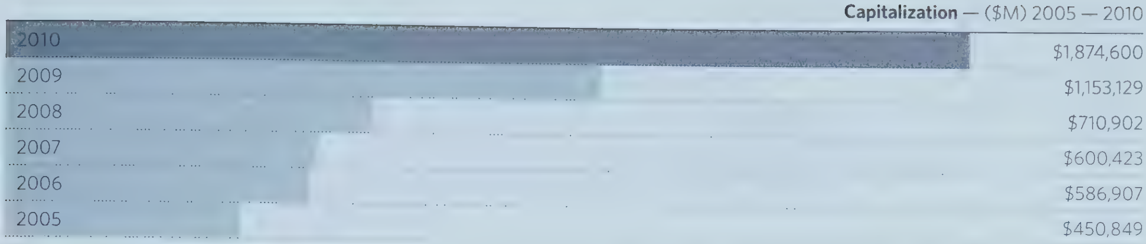
During 2010, Celtic issued 1.8 million common shares, upon exercise of stock options, at an average price of $6.32 per share for proceeds of $11.1 million. In April 2009, the Company issued 5.5 million common shares by way of a short-form prospectus, at an issue price of $6.625 per share, resulting in gross proceeds of $36.4 million. During 2009, upon exercise of stock options, Celtic also issued 1.0 million common shares at an average price of $5.14 per share for proceeds of $5.2 million.

Celtic has a committed term credit facility with a syndicate of financial institutions, led by National Bank of Canada. The authorized borrowing amount under this facility as at December 31, 2010 is $215.0 million. An interim review was conducted by the financial institutions in the fourth quarter of 2010 and the borrowing base amount of $215.0 million was re-confirmed. The facilities are available for a period of 364 days, maturing on June 28, 2011 and may be extended for an additional 364 days. Repayments of principal are not required provided that the borrowings under the facility do not exceed the authorized borrowing amount and the Company is in compliance with all covenants, representations and warranties. Covenants include a current ratio test, reporting requirements, permitted indebtedness, permitted dispositions, permitted hedging, permitted encumbrances and other standard business operating covenants. The authorized borrowing amount is subject to interim reviews by the financial institutions. As at December 31, 2010, the Company is in compliance with all covenants. Security is provided for by a first fixed and floating charge debenture over all assets in the amount of $500.0 million and general assignment of book debts.

At December 31, 2010, Celtic had drawn $160.8 million, leaving sufficient unused credit lines available to fund on-going capital expenditures. In order to fund all capital expenditures incurred in 2010, the Company augmented its equity issues and bank borrowings by generating $155.0 million in cash provided by operating activities for the year ended December 31, 2010.

Celtic expects to fund future capital expenditures through the use of a combination of cash provided by operating activities and bank debt, supplemented by new equity share offerings, as required.

Capitalization — ($M) 2005 — 2010



WORKING CAPITAL

The capital intensive nature of Celtic's activities may create a working capital deficiency position during periods with high levels of capital investment. However, during such periods, the Company maintains sufficient unused bank credit lines to satisfy such working capital deficiencies. At December 31, 2010, the working capital amount including outstanding bank debt represented 94% of the Company's maximum authorized bank borrowing credit limit.

The oil and gas industry has a pre-arranged monthly clearing day for payment of revenues from all buyers of oil and natural gas. This occurs on the 25th day following the month of sale. As a result, the Company's production revenues are collected in an orderly fashion. Celtic monitors its revenue counterparty credit positions to mitigate any potential credit losses. To the extent that the Company has joint venture partners in its activities, it must collect the partners' share of capital expenditures and operating expenses on a monthly basis. Exceptions are in the event that the partners' share of a capital project is a significant amount. In this case, Celtic will collect such amounts from its partners in advance of expenditures taking place in accordance with standard industry operating procedures. At December 31, 2010, the Company did not have any material accounts receivable that were deemed uncollectible, except as noted below.

Celtic has expensed $31.2 million ($13.2 million in 2009 and $18.0 million in 2008) as a provision for non-recoverable accounts receivable relating to a total financial exposure of approximately $32.5 million. The exposure was created with the announcement by SemCAMS ULC ("SemCAMS"), a Canadian subsidiary of U.S. based SemGroup LP ("SemGroup"), whereby SemGroup filed a voluntary petition for reorganization under Chapter 11 of the U.S. Bankruptcy Code and SemCAMS filed an application to obtain an order under the Companies' Creditors Arrangement Act Canada ("CCAA") in the Court of Queen's Bench of Alberta Judicial District of Calgary. The total amount of the financial exposure primarily relates to the Company's natural gas and associated by-product sales to SemCAMS during the period from June 1, 2008 to July 21, 2008.

Accounts payable consist of amounts payable to suppliers relating to head office and field operating and investing activities. These invoices are processed within the Company's normal payment period.

Celtic actively manages the pace of its capital spending program by monitoring forecasted production and commodity prices and resulting cash flows. Should circumstances affect cash flow in a detrimental way, the Company is capable of reducing capital investment levels.

LIQUIDITY

Liquidity risk is the risk the Company will encounter difficulties in meeting its financial liability obligations. The Company's financial liabilities are comprised of accounts payable, accrued liabilities and bank debt.

During 2009 and 2010, many oil and gas companies faced a number of challenges resulting from weakening commodity prices and tight credit markets.

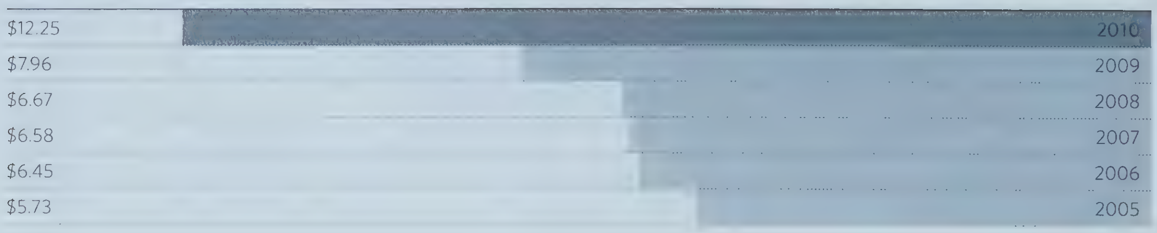
The Company manages liquidity risk through the prudent use of debt, interest rate, currency and commodity price risk management and through an actively managed production and capital expenditure budget process.

SHARE INFORMATION

The Company is authorized to issue an unlimited number of common shares and an unlimited number of preferred shares. The Company's shareholders approved a two-for-one stock split effective May 6, 2010. All references to common shares and stock options in this document are on a post stock split basis. As at December 31, 2010, there were 90.9 million common shares outstanding (as at March 6, 2011, there were 91.5 million common shares outstanding). There are no preferred shares outstanding.

As at December 31, 2010, directors, employees and certain consultants have been granted options to purchase 6.5 million common shares of the Company at an average exercise price of $8.31 per share. Detailed information regarding the Company's stock options outstanding is contained in the notes to the financial statements.

Average stock trading price — 2005 — 2010



The Company's common shares trade on the Toronto Stock Exchange ("TSX") under the symbol "CLT". During 2010, 85.5 million shares traded on the TSX at a weighted average price of $12.25 per share. These volumes were 6% higher than the 80.7 million shares traded in 2009 at a weighted average price of $7.96 per share.

The following table outlines Celtic's common share trading activity by quarter during the years 2010 and 2009:

SHARE TRADING ACTIVITY (CLT)	Q1	Q2	Q3	Q4	**2010**
High ($)	11.62	12.34	13.39	18.52	**18.52**
Low ($)	9.53	8.76	10.76	11.82	**8.76**
Close ($)	9.78	10.97	12.92	17.72	**17.72**
Volume traded *(thousands)*	18,475	24,295	21,614	21,068	**85,452**
Value traded *($ thousands)*	194,748	253,309	267,139	331,609	**1,046,805**
Weighted average trading price ($)	10.54	10.43	12.36	15.74	**12.25**
	Q1	**Q2**	**Q3**	**Q4**	**2009**
High ($)	7.25	8.60	9.73	10.75	10.75
Low ($)	5.26	6.50	6.56	8.78	5.26
Close ($)	6.87	7.63	9.55	10.45	10.45
Volume traded *(thousands)*	19,624	23,590	15,176	22,350	80,740
Value traded *($ thousands)*	125,142	175,359	123,512	219,005	643,018
Weighted average trading price ($)	6.38	7.43	8.14	9.80	7.96

FUTURE COMMITMENTS - FINANCIAL INSTRUMENTS

The Company may, from time to time, enter into fixed price contracts and derivative financial instruments with respect to oil and gas sales, currency exchange and interest rates in order to secure a certain amount of cash flow to protect a desired level of capital spending.

The following is a summary of NYMEX West Texas Intermediate ("WTI") light sweet oil fixed price contracts in effect:

Daily quantity	Remaining term of contract	Fixed price per bbl
1,000 bbls per day	January 1 to December 31, 2011	CA$ 90.00
1,000 bbls per day	February 1 to December 31, 2011	CA$ 91.80

The following is a summary of interest rate swap contracts that settle based on the floating Canadian Dollar Banker Acceptance CDOR rate, in effect as at December 31, 2010:

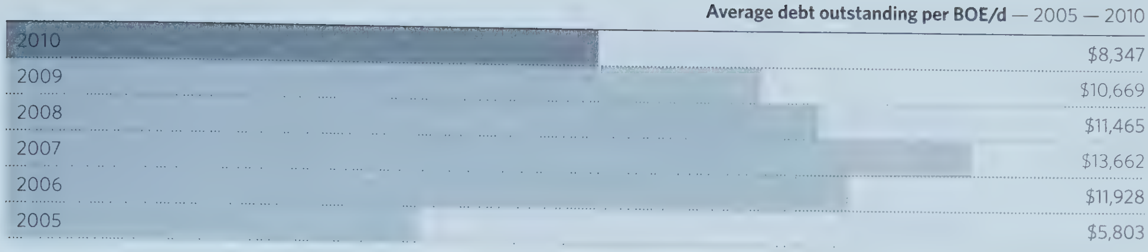
Amount	Remaining term of contract	Fixed interest rate
CA$ 100,000,000	January 1 to April 21, 2011	2.07%

CONTRACTUAL OBLIGATIONS

Celtic has a committed term credit facility with certain financial institutions. At December 31, 2010, the Company had bank debt outstanding in the amount of $160.8 million. The authorized borrowing amount available under the term credit facility is $215.0 million and is available on a revolving basis until June 28, 2011. Commencing on June 28, 2011, the Company may request the facility be available on a non-revolving basis for a period of one year thereafter, subject to approval by lenders with commitments of at least two thirds of the credit facility amount.

From time to time, the Company enters into agreements to transport and market oil and gas production. In addition, the Company has entered into agreements with third parties that provides employees with access to specialized computer software and information including production and reserves data, geological data, accounting systems and land management systems.

Average debt outstanding per BOE/d — 2005 — 2010



As a normal course of business, the Company leases office space, vehicles for field personnel and office equipment such as computers, printers and photocopiers. The Company is committed to future payments under the following agreements:

CONTRACTUAL OBLIGATIONS
($ thousands)

	2011	2012	2013	2014	2015	2016	Total
Operating lease - office building	$ 411	$ 515	$ 515	$ 515	$ 515	$ 215	$ 2,686
Operating lease - vehicles	178	77	34	–	–	–	289
Firm transportation agreements	32	–	–	–	–	–	32
Total	**$ 621**	**$ 592**	**$ 549**	**$ 515**	**$ 515**	**$ 215**	**$ 3,007**

Office building operating lease relates to rental office space in Calgary, Alberta. The current lease expires on April 30, 2011 and a new lease that commences on May 1, 2011 will expire on May 31, 2016.

RELATED PARTY AND OFF-BALANCE SHEET TRANSACTIONS

The Company has retained the law firm of Borden Ladner Gervais LLP ("BLG") to provide Celtic with legal services. William C. Guinan, a director, chairman and corporate secretary of Celtic is a partner of this law firm. During the twelve months ended December 31, 2010, the Company incurred $0.3 million to BLG for legal fees and disbursements. These amounts have been recorded at the exchange amount. The Company expects to continue using the services of this law firm from time to time.

Celtic was not involved in any off-balance sheet transactions in the years ended December 31, 2009 and 2010.

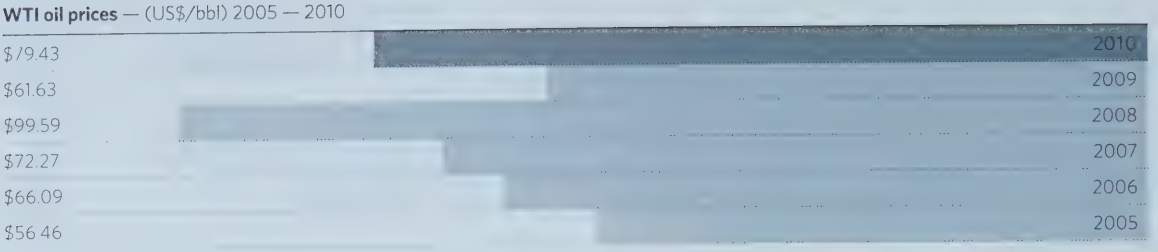
SUPPLEMENTAL QUARTERLY INFORMATION

The Company has been successful in providing strong growth in funds from operations and oil and gas production. The following tables summarize key financial and operating information by quarter:

QUARTERLY FINANCIAL INFORMATION
($ thousands, except per share amounts)

	Q1	Q2	Q3	Q4	**Total**
2010					
Revenue, before royalties and financial instruments	63,808	57,202	47,989	53,042	**222,041**
Funds from operations	35,083	34,122	30,963	30,625	**130,793**
Funds from operations per share - basic	0.39	0.38	0.34	0.34	**1.46**
Funds from operations per share - diluted	0.38	0.37	0.34	0.33	**1.43**
Net earnings (loss)	5,605	4,827	(799)	(3,050)	**6,583**
Earnings (loss) per share - basic	0.06	0.05	(0.01)	(0.03)	**0.07**
Earnings (loss) per share - diluted	0.06	0.05	(0.01)	(0.03)	**0.07**
Capital expenditures, net	(5,995)	38,138	72,456	68,186	**172,785**
Total assets	652,604	655,507	687,866	723,025	**723,025**
Bank debt, net of working capital	126,483	125,858	168,218	202,683	**202,683**
2009					
Revenue, before royalties and financial instruments	41,435	30,668	40,364	60,146	172,613
Funds from operations	28,140	20,008	27,874	42,003	118,025
Funds from operations per share - basic	0.68	0.46	0.63	0.94	2.72
Funds from operations per share - diluted	0.68	0.46	0.62	0.93	2.70
Net earnings (loss)	(5,039)	(5,459)	(13,666)	906	(23,258)
Earnings (loss) per share - basic	(0.12)	(0.13)	(0.31)	0.02	(0.54)
Earnings (loss) per share - diluted	(0.12)	(0.13)	(0.31)	0.02	(0.54)
Capital expenditures, net	41,583	36,619	29,040	41,519	148,761
Total assets	658,765	663,531	657,919	678,770	678,770
Bank debt, net of working capital	160,974	145,976	159,319	168,417	168,417

WTI oil prices — (US$/bbl) 2005 — 2010



QUARTERLY OPERATING INFORMATION	Q1	Q2	Q3	Q4	**Total**
2010					
Production					
Oil *(bbls/d)*	4,297	4,144	3,747	4,096	**4,070**
Natural gas *(mcf/d)*	78,031	83,311	76,555	79,731	**79,404**
Combined *(BOE/d)*	17,302	18,029	16,506	17,385	**17,304**
Production per million shares *(BOE/d)*	193	201	183	192	**193**
Realized sales prices, after financial instruments					
Oil *($/bbl)*	70.65	69.12	62.29	68.56	**67.80**
Natural gas *($/mcf)*	5.19	4.17	4.22	3.93	**4.37**
Combined *($/BOE)*	40.93	35.20	33.73	34.21	**36.00**
Operating netbacks, after financial instruments					
Oil *($/bbl)*	43.03	48.22	42.76	47.79	**45.50**
Natural gas *($/mcf)*	3.10	2.52	2.66	2.77	**2.76**
Combined *($/BOE)*	24.68	22.75	22.08	23.96	**23.38**
2009					
Production					
Oil *(bbls/d)*	3,601	2,939	3,813	4,384	3,687
Natural gas *(mcf/d)*	57,706	47,822	68,964	77,339	63,028
Combined *(BOE/d)*	13,219	10,909	15,307	17,274	14,192
Production per million shares *(BOE/d)*	320	251	346	388	327
Realized sales prices, after financial instruments					
Oil *($/bbl)*	79.01	86.32	79.71	80.22	81.00
Natural gas *($/mcf)*	5.36	3.77	3.39	4.86	4.36
Combined *($/BOE)*	44.54	39.78	35.11	42.17	40.43
Operating netbacks, after financial instruments					
Oil *($/bbl)*	50.32	60.85	57.88	58.66	56.87
Natural gas *($/mcf)*	2.74	1.52	1.67	3.01	2.30
Combined *($/BOE)*	25.29	23.06	21.94	28.42	25.00

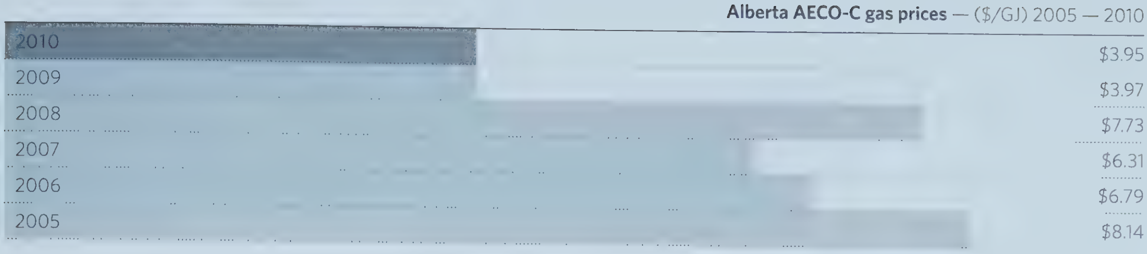
The majority of Celtic's production growth has been the result of the Company's successful exploration and development drilling activities. The Company estimates that over 80% of fourth quarter 2010 production came from exploration and development activities and the balance from acquisitions.

In addition to drilling activities, oil and gas property acquisitions completed in 2008 have also contributed to production growth. In 2008, Celtic completed the acquisition of complementary liquids-rich natural gas properties in the Kaybob South area of west central Alberta for approximately $44.9 million, adding approximately 928 BOE/d (68% natural gas and 32% natural gas liquids) at the time of the acquisition.

BUSINESS RISKS

Celtic's exploration and production activities are concentrated in the Western Canadian Sedimentary Basin, where activity is highly competitive and includes a variety of different sized companies ranging from smaller junior producers, intermediate and senior producers and royalty trust organizations, to the much larger integrated petroleum companies. Celtic is subject to a number of risks which are also common to other organizations involved in the oil and gas industry. Such risks include finding and developing oil and

Alberta AECO-C gas prices — ($/GJ) 2005 — 2010



gas reserves at economic costs, estimating amounts of recoverable reserves, production of oil and gas in commercial quantities, marketability of oil and gas produced, fluctuations in commodity prices, financial and liquidity risks and environmental and safety risks.

In order to reduce exploration risk, Celtic employs highly qualified and motivated professional employees who have demonstrated the ability to generate quality proprietary geological and geophysical prospects. To maximize drilling success, Celtic explores in areas that afford multi-zone prospect potential, targeting a range of shallower low to moderate risk prospects with some exposure to select deeper high-risk prospects with high-reward opportunities.

Celtic has retained an independent engineering consulting firm that assists the Company in evaluating recoverable amounts of oil and gas reserves. Values of recoverable reserves are based on a number of variable factors and assumptions such as commodity prices, projected production, future production costs and government regulation. Such estimates may vary from actual results.

The Company mitigates its risk related to producing hydrocarbons through the utilization of the most advanced technology and information systems. In addition, Celtic strives to operate the majority of its prospects, thereby maintaining operational control. The Company does rely on its partners in jointly owned properties that Celtic does not operate.

Celtic is exposed to market risk to the extent that the demand for oil and gas produced by the Company exists within Canada and the United States. External factors beyond the Company's control may affect the marketability of oil and gas produced. These factors include commodity prices and variations in the Canada-United States currency exchange rate, which in turn respond to economic and political circumstances throughout the world. Oil prices are affected by worldwide supply and demand fundamentals while natural gas prices are affected by North American supply and demand fundamentals. Celtic may periodically use futures and options contracts to hedge its exposure against the potential adverse impact of commodity price volatility.

Exploration and production for oil and gas is very capital intensive. As a result, the Company relies on equity markets as a source of new capital. In addition, Celtic utilizes bank financing to support on-going capital investment. Funds from operations also provide Celtic with capital required to grow its business. Equity and debt capital is subject to market conditions and availability may increase or decrease from time to time. Funds from operations also fluctuate with changing commodity prices.

SAFETY AND ENVIRONMENT

Oil and gas exploration and production can involve environmental risks such as pollution of the environment and destruction of natural habitat, as well as safety risks such as personal injury. The Company conducts its operations with high standards in order to protect the environment and the general public. Celtic maintains current insurance coverage for comprehensive and general liability as well as limited pollution liability. The amount and terms of this insurance are reviewed on an ongoing basis and adjusted as necessary to reflect current corporate requirements, as well as industry standards and government regulations.

CLIMATE CHANGE

World leaders gathered in Copenhagen in December 2009 to discuss climate policy. Even though consensus was not achieved, the message from the Copenhagen Accord was clear: greenhouse gases ("GHG") and other air pollutants must be regulated in order to deal effectively with climate change. GHG emissions can be measured as carbon dioxide equivalents ("CO_2E") and would consist of carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulphur hexafluoride.

The Federal Government of Canada has announced its intention to regulate GHG and other air pollutants. As these regulations are under development, the Company is unable to predict the total impact of the potential regulations upon its business.

The Alberta Government has set targets for GHG emission reductions. Alberta Environment required all facilities that exceeded 100,000 tonnes of CO_2E to reduce their GHG emissions intensity by 12% versus an established baseline emissions intensity. In order to comply with the Alberta regulations, companies can make operating improvements to its facilities, purchase carbon offsets or make a monetary contribution to the Alberta Climate Change and Emissions Management Fund.

BUSINESS OUTLOOK

ADVISORY REGARDING FORWARD-LOOKING STATEMENTS

This document contains expectations, beliefs, plans, goals, objectives, assumptions, information and statements about future events, conditions, results of operations or performance that constitute "forward-looking information" or "forward-looking statements" (collectively, "forward-looking statements") under applicable securities laws. Undue reliance should not be placed on forward-looking statements. Forward-looking statements are based on current expectations, estimates and projections that involve a number of risks and uncertainties, which could cause actual results to differ materially from those anticipated by the Company and described in the forward-looking statements. We caution that the foregoing list of risks and uncertainties is not exhaustive. Events or circumstances could cause actual dates to differ materially from those estimated or projected and expressed in, or implied by, these forward-looking statements. The forward-looking statements contained in this document are made as of the date hereof and the Company does not intend, and does not assume any obligation, to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise unless expressly required by applicable securities laws.

CURRENT ECONOMIC ENVIRONMENT

After the financial community around the world was rocked with unprecedented losses and business failures in 2009, the recovery that commenced in 2010 appears to be progressing, however, the current economic environment remains challenging and uncertain. Political upheaval in the Middle East remains a wild card and could hamper world economic recovery if oil supply is negatively affected. Celtic expects to see an improving economic environment in 2011, with improving natural gas prices, stable oil prices, less volatile financial markets and good access to capital markets.

In this environment, Celtic has maintained financial flexibility through the prudent use of bank debt and through an active risk management strategy whereby a portion of cash flow for 2011 has been secured to a certain extent through the use of oil price financial instruments.

Celtic's capital expenditure program remains flexible and if the current economic environment deteriorates, the Company has the ability to defer expenditures into the future.

2011 GUIDANCE

Celtic continues to remain optimistic about its future prospects. Celtic is opportunity driven and is confident that it can continue to grow the Company's production base by building on its current inventory of development prospects and by adding new exploration prospects. Celtic will endeavour to maintain a high quality product stream that on an historical basis receives a superior price with reasonably low production costs. In addition, the Company takes advantage of royalty incentive programs in order to further increase netbacks. Celtic will continue to focus its exploration efforts in areas of multi-zone hydrocarbon potential.

Celtic's Board of Directors has approved a capital expenditure budget in the amount of $180.0 million for 2011. Capital spending for 2011 is expected to be financed by funds from operations, with access to available bank credit lines and common share issuances, if necessary.

Celtic expects production in 2011 to average between 20,400 and 20,800 BOE per day. After taking into account non-core asset dispositions, delayed timing of adding field compression at Kaybob and timing of production on-stream dates from the newer plays at Resthaven and the Kaybob Duvernay, Celtic expects production growth in 2011 to be weighted towards the second half of the year, as production during the first half of 2011 is expected to remain relatively flat. Production in the fourth quarter of 2010 was 17,385 BOE per day.

The production mix for 2011 is expected to be 22% oil and 78% gas. At the low end of the range of 2011's production forecast, this represents an 18% increase from the average production of 17,304 BOE/d for 2010.

Celtic expects to achieve continued improvement in its cost structure in 2011. Production expense is estimated to be $7.95 per BOE, transportation expense is estimated to be $0.48 per BOE, royalties are expected to average 11.0% and general and administrative expense is estimated to be at industry low levels of $0.71 per BOE.

The Company's average commodity price assumptions for 2011 are US$85.00 per barrel for WTI oil, US$4.75 per mmbtu for NYMEX natural gas, $3.95 per GJ for AECO natural gas and a US/Canadian dollar exchange rate of US$1.000. These prices compare to average 2010 prices of US$79.43 per barrel for WTI oil, US$4.39 per mmbtu for NYMEX natural gas, $3.94 per GJ for AECO natural gas and a US/Canadian dollar exchange rate of US$0.971.

After giving effect to the aforementioned production and commodity price assumptions, funds from operations for 2011 is forecasted to be approximately $159.0 million or $1.70 per share, diluted and net earnings are forecasted to be approximately $12.0 million or $0.13 per share, diluted.

Changes in forecasted commodity prices and variances in production estimates can have a significant impact on estimated funds from operations and net earnings. Please refer to the advisory regarding forward-looking statements above.

Sensitivities to changes in commodity prices would affect forecasted 2011 funds from operations and net earnings as follows:
(i) Change in AECO natural gas price of $1.00 per GJ would affect funds from operations by $33.4 million ($0.36 per share) and earnings by $23.7 million ($0.25 per share);
(ii) Change in WTI oil price of US$10.00 per barrel would affect funds from operations by $4.5 million ($0.05 per share) and earnings by $3.2 million ($0.03 per share); and
(iii) Change in US/Canadian dollar exchange rate of US$0.05 per CAD would affect funds from operations by $9.3 million ($0.10 per share) and earnings by $6.6 million ($0.07 per share).

Bank debt, net of working capital, is estimated to be $178.5 million by the end of 2011 or approximately 1.1 times forecasted 2011 funds from operations.

Celtic is excited about the growth prospects being generated in the Company and remains optimistic about the Company's ability to deliver continued per share growth in production, reserves, net asset value and funds from operations. Given the Company's strong inventory of drilling locations, we look forward to continued growth in 2011 and beyond.

The information set out herein under the heading "Production and Financial Guidance" is "financial outlook" within the meaning of applicable securities laws. The purpose of this financial outlook is to provide readers with disclosure regarding Celtic's reasonable expectations as to the anticipated results of its proposed business activities for 2011. Readers are cautioned that this financial outlook may not be appropriate for other purposes.

ADDITIONAL INFORMATION

Additional information relating to Celtic, including the Company's Annual Information Form ("AIF") is filed on SEDAR and can be viewed on their website at www.sedar.com. Copies of the AIF can also be obtained by contacting Sadiq H. Lalani, Vice President, Finance and Chief Financial Officer at Celtic Exploration Ltd., Suite 500, 505 Third Street SW, Calgary, Alberta, Canada, T2P 3E6. Further information relating to the Company is also available on its website at www.celticex.com.

MANAGEMENT'S REPORT

Management has prepared the accompanying financial statements of Celtic Exploration Ltd. in accordance with Canadian generally accepted accounting principles. Financial information presented throughout this annual report is consistent with that shown in the financial statements.

Management is responsible for the integrity of the financial information. Where appropriate, management has made informed judgments and estimates in accounting for transactions which affect the current accounting period but cannot be finalized with certainty until future periods. Internal control systems are designed and maintained to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and to produce reliable accounting records for financial reporting purposes.

PricewaterhouseCoopers LLP was appointed by the Company's shareholders to perform an examination of the corporate and accounting records so as to express an opinion on the financial statements. Their examination included a review and evaluation of Celtic's internal control systems and included such tests and procedures, as they considered necessary, to provide reasonable assurance that the financial statements are presented fairly in accordance with Canadian generally accepted accounting principles.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board exercises this responsibility with the assistance of the Audit Committee. This Committee, consisting of nonmanagement directors, meets with management and independent auditors to ensure that each group is properly discharging its responsibilities and to discuss adequacy of internal controls, accounting policies and financial reporting matters. The Audit Committee has reviewed the financial statements and has reported thereon to the Board of Directors. The Board has approved the financial statements for issuance to the shareholders.

David J. Wilson
President and Chief Executive Officer

Sadiq H. Lalani
Vice President, Finance and Chief Financial Officer

March 6, 2011

INDEPENDENT AUDITOR'S REPORT

To the Shareholders of Celtic Exploration Ltd.

We have audited the accompanying financial statements of Celtic Exploration Ltd., which comprise the balance sheets as at December 31, 2010 and 2009 and the statements of operations, retained earnings and accumulated other comprehensive income, and cash flows for the years then ended, and a summary of significant accounting policies and other explanatory information.

MANAGEMENT'S RESPONSIBILITY FOR THE FINANCIAL STATEMENTS
Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian Generally Accepted Auditing Standards, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

AUDITOR'S RESPONSIBILITY
Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian Generally Accepted Auditing Standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

OPINION
In our opinion, the financial statements present fairly, in all material respects, the financial position of Celtic Exploration Ltd. as at December 31, 2010 and December 31, 2009 and their financial performance and cash flows for the years ended December 31, 2010 and December 31, 2009 in accordance with Canadian Generally Accepted Accounting Standards.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, AB
March 6, 2011

BALANCE SHEET

($ thousands)		As at December 31 2010	As at December 31 2009
ASSETS			
Current assets			
Cash and cash equivalents		**$ 644**	$ 42
Accounts receivable		**41,535**	49,252
Drilling royalty credits	[Note 3]	**2,906**	13,158
Prepaid expenses and deposits		**4,870**	4,947
Fair value of financial instruments	[Note 10]	**0**	1,463
Future income tax asset		**698**	510
		50,653	69,372
Other assets		**5,800**	6,090
Property, plant and equipment	[Note 2]	**666,572**	603,308
		$ 723,025	$ 678,770
LIABILITIES			
Current liabilities			
Accounts payable and accrued liabilities		**$ 89,903**	$ 61,708
Fair value of financial instruments	[Note 10]	**2,633**	1,757
Future income tax liability		**0**	424
Bank debt	[Note 4]	**160,800**	173,900
		253,336	237,789
Asset retirement obligation	[Note 5]	**9,918**	6,588
Future income tax liability	[Note 7]	**51,676**	47,203
		$ 314,930	$ 291,580
SHAREHOLDERS' EQUITY			
Share capital	[Note 6]	**$ 296,065**	$ 282,990
Contributed surplus	[Note 6]	**6,547**	5,300
Retained earnings and accumulated other comprehensive income		**105,483**	98,900
		$ 408,095	$ 387,190
		$ 723,025	$ 678,770
Commitments	[Note 9]		
Contingencies	[Note 13]		

The accompanying notes form an integral part of these financial statements.

On behalf of the Board of Directors:

Director

Director

STATEMENT OF OPERATIONS

($ thousands, except per share amounts)		Twelve months ended December 31, 2010	Twelve months ended December 31, 2009
Revenue			
Oil and gas		**$ 222,041**	$ 172,613
Royalties		**(25,592)**	(22,968)
Realized gain on financial instruments		**3,693**	34,294
Unrealized gain (loss) on financial instruments		**(2,339)**	(33,523)
		$ 197,803	$ 150,416
Expenses			
Production		**$ 51,415**	$ 53,123
Transportation		**2,809**	3,819
Interest and financing		**5,853**	5,025
General and administrative		**4,612**	3,947
Stock based compensation	[Note 6]	**3,262**	2,362
Loss on disputed processing fees	[Note 13]	**4,660**	0
Provision for non-recoverable accounts receivable	[Note 10]	**0**	13,233
Depletion, depreciation and accretion	[Note 2]	**114,749**	101,808
		$ 187,360	$ 183,317
Earnings (loss) before taxes		**$ 10,443**	$ (32,901)
Provision for (recovery of) future income taxes		**3,860**	(9,643)
Net earnings (loss) and comprehensive income (loss)		**$ 6,583**	$ (23,258)
Earnings (loss) per share			
Basic		**$ 0.07**	$ (0.27)
Diluted	[Note 8]	**0.07**	(0.27)

STATEMENT OF RETAINED EARNINGS AND ACCUMULATED OTHER COMPREHENSIVE INCOME

($ thousands)	Twelve months ended December 31, 2010	Twelve months ended December 31, 2009
Retained earnings and accumulated other comprehensive income, beginning of period	**$ 98,900**	$ 122,158
Net earnings (loss) and comprehensive income (loss)	**6,583**	(23,258)
Retained earnings and accumulated other comprehensive income, end of period	**$ 105,483**	$ 98,900

The accompanying notes form an integral part of these financial statements.

STATEMENT OF CASH FLOWS

($ thousands)		Twelve months ended December 31, 2010	Twelve months ended December 31, 2009
Operating activities			
Net earnings (loss)		**$ 6,583**	$ (23,258)
Items not affecting cash:			
Depletion, depreciation and accretion		**114,749**	101,808
Provision for non-recoverable accounts receivable		**0**	13,233
Stock based compensation		**3,262**	2,362
Unrealized loss (gain) on financial instruments		**2,339**	33,523
Provision for (recovery of) future income taxes		**3,860**	(9,643)
Settlement of asset retirement obligations		**(1,897)**	(1,043)
Change in non-cash operating working capital	[Note 11]	**26,097**	(13,261)
Cash provided by operating activities		**$ 154,993**	$ 103,721
Financing activities			
Increase (decrease) in bank debt		**$ (13,100)**	$ 23,450
Issue of common shares, net of costs		**11,060**	39,798
Cash provided by (used in) financing activities		**$ (2,040)**	$ 63,248
Investing activities			
Property, plant and equipment expenditures		**$ (229,709)**	$ (146,964)
Property, plant and equipment acquisitions		**(7,703)**	(2,172)
Property, plant and equipment dispositions		**64,627**	375
Change in other assets		**290**	(2,808)
Change in non-cash investing working capital	[Note 11]	**20,144**	(15,431)
Cash used in investing activities		**$ (152,351)**	$ (167,000)
Net change in cash and cash equivalents		**$ 602**	$ (31)
Cash and cash equivalents, beginning of period		**42**	73
Cash and cash equivalents, end of period		**$ 644**	$ 42

The accompanying notes form an integral part of these financial statements.

NOTES TO THE FINANCIAL STATEMENTS

For the years ended December 31, 2010 and December 31, 2009
(All tabular amounts in thousands, unless otherwise stated)

1. SIGNIFICANT ACCOUNTING POLICIES

NATURE OF BUSINESS

Celtic Exploration Ltd. ("Celtic" or the "Company") was incorporated under the Business Corporations Act (Alberta) on April 16, 2002. Celtic is an oil and natural gas exploration, development and production company based in Calgary, Alberta, Canada. The Company's operations are focused in Western Canada, primarily in Alberta.

BASIS OF PRESENTATION

These financial statements are stated in Canadian dollars and have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements as well as the reported amounts of revenues, expenses and cash flows during the period. Actual results could differ from these estimates.

MEASUREMENT UNCERTAINTY

The amounts recorded for the fair value of financial instruments, stock based compensation, depletion and depreciation of assets, the provision for asset retirement obligation costs and the provision for future income taxes are based on estimates. In addition, the ceiling test calculation is based on estimates of proved reserves, production rates, oil and gas prices, future costs and other relevant assumptions. Accruals for revenue, expenses and capital expenditures are also based on estimates. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future periods could be material.

JOINT INTERESTS

A substantial portion of the Company's exploration, development and production activities is conducted jointly with others. These financial statements reflect only the Company's proportionate interest in such activities.

CASH AND CASH EQUIVALENTS

Cash and cash equivalents include cash on hand, demand deposits and investments in highly liquid money market instruments which are convertible to known amounts of cash in less than three months.

FINANCIAL INSTRUMENTS AND DERIVATIVES

GAAP prescribes when a financial asset, financial liability or non-financial derivative is to be recognized on the balance sheet and at what amount, requiring fair value or cost-based measures under different circumstances. All financial instruments must be – as one of the following five categories: loans and receivables; held-to-maturity investments; held-for-trading instruments; available-for-sale financial assets; or other financial liabilities. All financial instruments, with the exception of loans and receivables, held-to-maturity investments and other financial liabilities which are recorded at amortized cost, are reported on the balance sheet at fair value. Subsequent measurement and changes in fair value will depend on their initial classification. Available-for-sale financial assets are measured at fair value and unrealized gains or losses resulting from changes in fair value are recorded in other comprehensive income until the investment is de-recognized or impaired at which time the amounts would be recorded in earnings.

All derivative instruments, including embedded derivatives, are recorded on the balance sheet at fair value unless they qualify for the normal sale and purchase exception. All changes in fair value are included in earnings unless cash flow hedge or net investment accounting is used, in which case changes in fair value are recorded in other comprehensive income, to the extent the hedge is effective, and in earnings, to the extent it is ineffective.

OTHER ASSETS

Other assets are comprised mainly of oilfield equipment, well tubing and casing inventory. Oilfield equipment is valued at cost. Well tubing and casing inventory is valued at weighted average cost.

PROPERTY, PLANT AND EQUIPMENT

The Company follows the full cost method of accounting whereby all costs relating to the exploration and development of petroleum and natural gas reserves are capitalized. Such costs include land acquisition, geological and geophysical, drilling of productive and non-productive wells, production equipment and facilities, carrying costs directly related to unproved properties and costs related to acquisition of petroleum and natural gas assets directly or by means of a business combination. These capitalized costs along with estimated future capital expenditures to be incurred in order to develop proved reserves, are depleted on a unit of production basis using estimated proved petroleum and natural gas reserves as evaluated by independent engineers. For purposes of this calculation, petroleum and natural gas reserves are converted to a common unit of measurement on the basis of their relative energy content where six thousand cubic feet of gas equates to one barrel of oil. Costs of acquiring and evaluating unproved properties are excluded from costs subject to depletion until it is determined whether proved reserves are attributable to the properties or impairment occurs.

Gains or losses on the disposition of properties are not recognized unless the proceeds on disposition result in a change of 20 percent or more in the depletion rate.

Depreciation of furniture and office equipment is provided using the declining balance method at a rate of 25 percent.

The net amount at which petroleum and natural gas properties are carried is subject to a cost recovery test (the "ceiling test"). Under this test, an estimate is made of the ultimate recoverable amount from undiscounted future net cash flows based on proved reserves, which are determined by using forecasted future prices, plus unproved properties. If the carrying amount exceeds the ultimate recoverable amount, an impairment loss is recognized in net earnings. The impairment loss is limited to the amount by which the carrying amount exceeds: (i) the sum of the fair value of proved and probable reserves (the sum of all future cash flows associated with proved and probable reserves, discounted at the risk free rate); and (ii) the costs of unproved properties that have been subject to a separate impairment test and contain no probable reserves.

ASSET RETIREMENT OBLIGATIONS

Estimated future costs relating to retirement obligations associated with oil and gas well sites and facilities are recognized as a liability, at fair value at the time when the liability is incurred. The asset retirement cost, equal to the fair value of the retirement obligation, is capitalized as part of the cost of the related asset. These capitalized costs are amortized on a unit-of-production basis, consistent with depletion. The liability is adjusted at each reporting period to reflect the passage of time, with the accretion charged to earnings. Actual costs incurred upon settlement of the obligations are charged against the liability.

FUTURE INCOME TAXES

The Company follows the liability method of accounting for income taxes. Temporary differences arising from the differences between the tax basis of an asset or liability and its carrying amount on the balance sheet are used to calculate future income tax assets or liabilities. Future income tax assets or liabilities are calculated using tax rates anticipated to apply in the periods that the temporary differences are expected to reverse.

FLOW-THROUGH SHARES

Resource expenditure deductions for income tax purposes related to exploration and development activities funded by flow-through share issues are renounced to investors in accordance with income tax legislation. The estimated tax benefits transferred to shareholders are recorded as a future income tax liability and a reduction in share capital, at the time the renunciation documents are filed with the appropriate tax authorities.

REVENUE RECOGNITION

Revenue from the sale of oil, natural gas and associated by-products is recorded when title passes to a third party and collectibility is reasonably assured.

STOCK-BASED COMPENSATION

The Company has a stock-based compensation plan and uses the fair-value method to record compensation expense with respect to stock options granted. The fair value of each option granted is estimated on the date of grant and a provision for the costs is provided for as contributed surplus over the vesting period outlined in the option agreement. The consideration received by the Company on the exercise of share options is recorded as an increase to share capital together with corresponding amounts previously recognized in contributed surplus. Forfeitures are accounted for as they occur which could result in recoveries of the compensation expense.

COMPREHENSIVE INCOME

Comprehensive income is defined as the change in equity from transactions and other events from non-owner sources and other comprehensive income comprises revenues, expenses, gains and losses that, in accordance with GAAP, are recognized in comprehensive income but excluded from net earnings.

PER SHARE AMOUNTS

Basic per share amounts are calculated using the weighted average number of shares outstanding during the year. Weighted average number of shares is determined by relating the portion of time within the reporting period that common shares have been outstanding to the total time in that period.

Diluted per share amounts are calculated using the treasury stock method which assumes that any proceeds obtained on exercise of share options or other dilutive instruments would be used to purchase common shares at the average market price during the period. The weighted average number of shares outstanding is then adjusted by the net change.

CHANGES IN ACCOUNTING POLICIES AND PRACTICES

Effective January 1, 2010, the Company adopted the following Canadian Institute of Chartered Accountants ("CICA") Handbook sections:

Section 1582, "Business Combinations", which replaces the previous business combinations standard. The standard requires assets and liabilities acquired in a business combination to be measured at their fair values as of the date of acquisition. The adoption of this standard will impact the accounting treatment of future business combinations entered into after January 1, 2010.

Section 1601, "Consolidated Financial Statements", which replaces the previous consolidated financial statements standard. This section establishes the requirements for the preparation of consolidated financial statements. The adoption of this section does not impact Celtic's financial statements at this time.

Section 1602, "Non-controlling Interests", which establishes the accounting for a non-controlling interest in a subsidiary to be classified as a separate component of equity. In addition, net earnings and components of other comprehensive income are attributed to both the parent and non-controlling interest. The adoption of this section has no impact on Celtic's financial statements at this time.

Celtic will be required to report its results in accordance with International Financial Reporting Standards ("IFRS") beginning in 2011.

2. PROPERTY, PLANT AND EQUIPMENT

	Cost	Accumulated depletion, depreciation and amortization	Net book value
At December 31, 2010			
Oil and gas properties, plant and equipment	$ 1,130,762	$ 465,316	$ 665,446
Furniture and office equipment	2,294	1,168	1,126
Total	$ 1,133,056	$ 466,484	$ 666,572
At December 31, 2009			
Oil and gas properties, plant and equipment	$ 953,673	$ 351,200	$ 602,473
Furniture and office equipment	1,743	908	835
Total	$ 955,416	$ 352,108	$ 603,308

At December 31, 2010, oil and gas properties with a cost of $67.8 million (December 31, 2009 - $39.0 million) relating to unproved properties have been excluded from the depletion and depreciation calculation. Future capital costs required to develop proved reserves in the amount of $131.3 million (2009 - $90.5 million) are included in the depletion and depreciation calculation.

During the twelve months ended December 31, 2009, the Company capitalized $0.4 million (2009 - $0.4 million) with respect to employee salaries directly relating to exploration and development activities.

As a result of ceiling test calculations at December 31, 2010 and December 31, 2009, the Company was not required to record an impairment loss.

The Company performed the impairment test as of December 31, 2010 using the estimated average sales price for each of the next five years as follows:

	2011	2012	2013	2014	2015
Oil *($/bbl)*	$ 85.40	$ 86.81	$ 85.00	$ 84.36	$ 85.38
NGLs *($/bbl)*	73.22	74.56	74.69	74.93	76.18
Natural gas *($/mcf)*	4.13	4.78	5.14	6.85	6.97

Prices escalate at varying percentages in a range between 1.0% and 1.8% thereafter.

For comparative purposes the forecasted future prices used for the next five years in the impairment test evaluation of the Company's proved reserves as at December 31, 2009 were as follows:

	2010	2011	2012	2013	2014
Oil *($/bbl)*	$ 78.34	$ 83.91	$ 85.37	$ 88.16	$ 89.36
NGLs *($/bbl)*	66.24	71.50	73.95	77.21	79.05
Natural gas *($/mcf)*	5.56	6.48	6.72	7.58	8.39

Prices escalate at varying percentages in a range between 1.7% and 2.4% thereafter.

3. DRILLING ROYALTY CREDITS

	December 31, 2010	December 31, 2009
Drilling royalty credits, beginning of period	$ 13,158	$ -
Credits earned through drilling	30,582	20,618
Credits claimed	(11,533)	(7,460)
Credits deemed un-claimable	(29,301)	-
Drilling royalty credits, end of period	$ 2,906	$ 13,158

The Drilling Royalty Credit ("DRC") program introduced by the Alberta government in 2009 provides companies with a $200 per metre credit on wells drilled. These credits can be applied against corporate Crown royalties payable during the period from April 1, 2009 to March 31, 2011, subject to a maximum of 50% of corporate Crown royalties for Celtic. Credits earned are recorded as a reduction of property, plant and equipment, with reasonable assurance that credits can be claimed in a future period. During the twelve month period ended December 31, 2010, property, plant and equipment was reduced by $1.3 million (year ended December 31, 2009 - $20.6 million).

4. BANK DEBT

	December 31, 2010	December 31, 2009
Bank loan	$ 30,800	$ 23,900
Bankers' acceptances	130,000	150,000
Total bank debt	$ 160,800	$ 173,900

Celtic has a committed term credit facility with a syndicate of financial institutions, led by National Bank of Canada. The authorized borrowing amount under this facility as at December 31, 2010 is $215.0 million. The facilities are available for a period of 364 days, maturing on June 28, 2011 and may be extended for an additional 364 days. Repayments of principal are not required provided that the borrowings under the facility do not exceed the authorized borrowing amount and the Company is in compliance with all covenants, representations and warranties. Covenants include a current ratio test, reporting requirements, permitted indebtedness, permitted dispositions, permitted hedging, permitted encumbrances and other standard business operating covenants. The authorized borrowing amount is subject to interim reviews by the financial institutions. As at December 31, 2010, the Company is in compliance with all covenants. Security is provided for by a first fixed and floating charge debenture over all assets in the amount of $500.0 million and general assignment of book debts.

Interest is payable monthly for borrowings through direct advances. Interest rates fluctuate based on a pricing grid and range from bank prime plus 1.25% to bank prime plus 3.25%, depending upon the Company's then current debt to cash flow ratio of between less than one and one tenth times to greater than three times. Under the credit facility, borrowings through the use of bankers' acceptances are also available. Stamping fees fluctuate based on a pricing grid and range from 2.25% to 4.25%, depending upon the Company's then current debt to cash flow ratio of between less than one and one tenth times to greater than three times.

The Company has entered into an interest rate swap transaction whereby borrowings through bankers' acceptances in the amount of $100.0 million has been fixed at an annual interest rate of 2.07% from April 22, 2010 to April 21, 2011, before bank stamping fees.

5. ASSET RETIREMENT OBLIGATION

The following table provides a reconciliation of the carrying amount of the obligation associated with the retirement of oil and gas properties:

	December 31, 2010	December 31, 2009
Asset retirement obligation, beginning of year	$ 6,588	$ 5,834
Liabilities incurred, net of liabilities disposed	1,966	225
Liabilities settled	(1,897)	(1,043)
Revisions to estimated liabilities	2,889	1,052
Accretion expense	372	520
Asset retirement obligation, end of year	$ 9,918	$ 6,588

The key assumptions, on which the carrying amount of the asset retirement obligations is based, include a credit-adjusted risk-free rate of 8.5% (2009 - 8.5%) and an inflation rate of 2.7% (2009 - 2.7%). The total undiscounted amount of the estimated cash flows required to settle the obligations is $32.1 million (December 31, 2009 - $31.0 million). The inflated value of estimated cash

flows required to settle the obligations at a future period at the time the asset is retired is $70.5 million (December 31, 2009 – $81.5 million). The expected timing of payment of the cash flows required to settle the obligations ranges from 1 year to 51 years.

6. SHARE CAPITAL

(A) AUTHORIZED

Unlimited number of common shares and preferred shares.

(B) ISSUED

The following table summarizes the changes in common shares outstanding for the years ended December 31, 2009 and December 31, 2010:

	Common Shares	Amount
Balance, December 31, 2008	82,612	$ 241,673
Issued for cash on exercise of stock options	1,013	5,205
Amount relating to exercised options previously recorded as contributed surplus	–	1,039
Issued for cash through public prospectus offering	5,500	36,437
Share issue costs, after future income taxes	–	(1,364)
Balance, December 31, 2009	89,125	$ 282,990
Issued for cash on exercise of stock options	1,751	11,060
Amount relating to exercised options previously recorded as contributed surplus	–	2,015
Balance, December 31, 2010	90,876	$ 296,065

(C) COMMON SHARE OFFERINGS

In April 2009, Celtic issued 5.5 million common shares by way of a short form prospectus at an issue price of $6.625 per share for gross proceeds of $36.4 million.

(D) STOCK OPTIONS

Celtic has a stock option plan that provides for granting of stock options to directors, officers, employees and certain consultants. Stock options granted under the stock option plan have a maximum term of five years to expiry. Vesting is determined by the Company's board of directors. However, the majority of the options granted vest equally over a three year period commencing on the first anniversary date of the grant. The exercise price of each stock option granted is determined as the closing market price of the common shares on the Toronto Stock Exchange at the time of grant. Each stock option granted permits the holder to purchase one common share of the Company at the stated exercise price.

The following table summarizes the changes in stock options outstanding during the years ended December 31, 2009 and December 31, 2010:

	Number of Options	Average Exercise Price
Balance, December 31, 2008	6,459	$ 6.48
Granted	1,170	7.95
Exercised	(1,013)	5.14
Balance, December 31, 2009	6,616	$ 6.95
Granted	2,049	10.70
Exercised	(1,751)	6.32
Forfeited/cancelled	(365)	6.97
Balance, December 31, 2010	6,549	$ 8.31

The Company uses the fair-value method to record stock based compensation expense with respect to stock options granted. The fair value of each option granted is estimated on the date of grant using the Black-Scholes option pricing model with weighted average assumptions for grants as follows:

	2010	2009
Risk free interest rate	0.54%	0.50%
Expected life (years)	3.0	3.0
Expected volatility	40%	30%
Expected dividend yield	-	-
Fair value of options granted during the year ($/share)	2.96	1.65

The following table summarizes information regarding stock options outstanding at December 31, 2010:

Range of exercise prices per share	Number of options outstanding	Weighted average remaining term in years	Weighted average exercise price per share for options outstanding	Number of options exercisable	Weighted average exercise price per share for options exercisable
$5.01 to $7.00	2,294	1.7	$ 6.20	1,981	$ 6.24
$7.01 to $9.00	1,990	3.0	8.04	1,003	8.17
$9.01 to $11.00	2,132	4.2	10.48	80	10.02
$11.01 to $13.00	78	4.7	12.39	-	-
$13.01 to $17.00	55	4.9	16.18	-	-
Total	6,549	3.0	$ 8.31	3,064	$ 6.97

(E) CONTRIBUTED SURPLUS

The following table reconciles the Company's contributed surplus for the years ended December 31, 2010 and December 31, 2009:

	December 31, 2010	December 31, 2009
Contributed surplus, beginning of year	$ 5,300	$ 3,977
Stock based compensation expense	3,262	2,362
Amount relating to exercised options	(2,015)	(1,039)
Contributed surplus, end of year	$ 6,547	$ 5,300

7. INCOME TAXES

(A) FUTURE INCOME TAX EXPENSE

The provision for income taxes differs from the expected amount calculated by applying the combined Federal and Provincial corporate income tax rate as a result of the following:

	2010	2009
Earnings (loss) before taxes	$ 10,443	$ (32,901)
Statutory combined federal & provincial income tax rate	28.00%	29.00%
Expected income taxes (recovery)	$ 2,924	$ (9,541)
Increase (decrease) resulting from:		
Non-deductible stock-based compensation expense	913	685
Benefit relating to changes in future income tax rates	-	(779)
Other adjustments	23	(8)
Provision for (recovery of) future income taxes	$ 3,860	$ (9,643)

(B) FUTURE INCOME TAX LIABILITY

The components of future income taxes are as follows:

	December 31, 2010	December 31, 2009
Future income tax liabilities:		
Property, plant and equipment	$ 54,880	$ 50,111
Unrealized financial instrument gains	-	424
Future income tax assets:		
Asset retirement obligation costs	(2,479)	(1,647)
Share issue costs	(686)	(1,222)
Unrealized financial instrument losses	(698)	(510)
Other income tax assets	(39)	(39)
Net future income tax liability	$ 50,978	$ 47,117
Net current portion	698	86
Future income taxes – non-current	$ 51,676	$ 47,203

8. EARNINGS PER SHARE

The Company uses the treasury stock method to determine the dilutive effect of stock options and other dilutive instruments. Under this method, only "in-the-money" dilutive instruments impact the calculations in computing diluted earnings per share.

In computing diluted earnings per share, 1.7 million (2009 – 0.7 million) shares were added to the 89.9 million (2009 – 86.8 million) weighted average number of common shares outstanding during the twelve month period for the dilutive effect of stock options. For the purpose of calculating the diluted net loss per share for the year ended December 31, 2009, the incremental shares from assumed exercise of stock options are not included due to their anti-dilutive effect.

9. COMMITMENTS

The Company is committed to future payments under the following agreements:

	2011	2012	2013	2014	2015	2016	Total
Operating lease – office building	$ 411	$ 515	$ 515	$ 515	$ 515	$ 215	$ 2,686
Operating lease – vehicles	178	77	34	–	–	–	289
Firm transportation agreements	32	–	–	–	–	–	32
	$ 621	$ 592	$ 549	$ 515	$ 515	$ 215	$ 3,007

Office building operating lease relates to rental office space in Calgary, Alberta. The current lease expires on April 30, 2011 and a new lease that commences on May 1, 2011 will expire on May 31, 2016.

At December 31, 2010, the Company had bank debt outstanding in the amount of $160.8 million. The Company has a $215.0 million term credit facility that is available on a revolving basis until June 28, 2011. Commencing on June 28, 2011, the Company may request the facility be available on a non-revolving basis for a period of one year thereafter, subject to approval by lenders with commitments of at least two thirds of the credit facility amount.

10. FINANCIAL INSTRUMENTS

(A) FAIR VALUES OF FINANCIAL ASSETS AND LIABILITIES

Financial instruments of the Company consist mainly of cash and cash equivalents, deposits, drilling royalty credits, receivables, payables, bank debt and assets and liabilities arising from the use of financial instrument risk management contracts, all of which are included in these financial statements.

The following table presents the Company's fair value measurements for each hierarchy level, as described in CICA Handbook Section 3862, as at December 31, 2010:

	Level 1 Inputs	Level 2 Inputs	Level 3 Inputs	Total
Crude oil swaps	–	$ (2,363)	–	$ (2,363)
Interest rate swaps	–	(270)	–	(270)
Net asset (liability)	–	$ (2,633)	–	$ (2,633)

At December 31, 2010, the classification of financial instruments and the carrying amounts reported on the balance sheet and their estimated fair values are as follows:

	Carrying Amount	Fair Value
Receivables and other financial assets (accounts receivable, drilling royalty credits and deposits)	$ 50,125	$ 50,125
Held-for-trading instruments (financial instruments and cash)	(1,989)	(1,989)
Other financial liabilities (accounts payable and bank debt)	(252,178)	(252,178)
Total	$(204,042)	$ (204,042)

At December 31, 2009, the classification of financial instruments and the carrying amounts reported on the balance sheet and their estimated fair values are as follows:

	Carrying Amount	Fair Value
Receivables and other financial assets (accounts receivable, drilling royalty credits and deposits)	$ 68,579	$ 68,579
Held-for-trading instruments (financial instruments and cash)	(252)	(252)
Other financial liabilities (accounts payable and bank debt)	(237,674)	(237,674)
Total	$ (169,347)	$ (169,347)

(B) CREDIT RISK

The majority of the Company's accounts receivable is in respect of oil and gas operations. Celtic generally extends unsecured credit to these third parties, and therefore, the collection of accounts receivable may be affected by changes in economic or other conditions and may accordingly impact the Company's overall credit risk.

The ageing of the Company's accounts receivable is summarized in the following table:

	Current	31 - 60 Days	61 - 90 Days	Over 90 Days	Total
December 31, 2010					
Accounts receivable	$ 35,912	$ 2,034	$ 648	$ 4,416	$ 43,010
December 31, 2009					
Accounts receivable	$ 42,814	$ 2,293	$ 704	$ 3,441	$ 49,252

Celtic has not experienced any material credit loss in the collection of receivables in 2010 and 2009, except as noted below.

Celtic has expensed $31.2 million ($13.2 million in 2009 and $18.0 million in 2008) as a provision for non-recoverable accounts receivable relating to a total financial exposure of approximately $32.5 million. The exposure was created with the announcement by SemCAMS ULC ("SemCAMS"), a Canadian subsidiary of U.S. based SemGroup LP ("SemGroup"), whereby SemGroup filed a voluntary petition for reorganization under Chapter 11 of the U.S. Bankruptcy Code and SemCAMS filed an application to obtain an order under the Companies' Creditors Arrangement Act Canada ("CCAA") in the Court of Queen's Bench of Alberta Judicial District of Calgary. The total amount of the financial exposure primarily relates to the Company's natural gas and associated by-product sales to SemCAMS during the period from June 1, 2008 to July 21, 2008.

(C) INTEREST RATE RISK

The Company is exposed to fluctuations in interest rates on its bank debt. Interest rate risk is mitigated through short-term fixed rate borrowings using bankers' acceptances and interest rate swap transactions.

The Company has entered into an interest rate swap transaction whereby the interest rate applicable to borrowings by way of bankers' acceptances has been fixed. Borrowings in the amount of $100.0 million have been fixed at an annual interest rate of 2.1% from April 22, 2010 to April 21, 2011, before bank stamping fees. The fair value of the remaining term of this contract, mark-to-market at December 31, 2010 is a liability of $0.3 million. If annual interest rates increase (decrease) by 1%, the fair market value of the remaining term of this contract would increase (decrease) by $0.3 million.

(D) FOREIGN EXCHANGE RATE RISK

The Company is exposed to the risk of changes in the Canadian/U.S. dollar exchange rate on sales of commodities that are denominated in U.S. dollars or directly influenced by U.S. dollar benchmark prices.

In order to mitigate a portion of the risk relating to revenue that is subject to fluctuations in the exchange rate, the Company has entered into commodity swap transactions whereby commodity prices denominated in U.S. dollars have been converted to Canadian dollars as described under the heading "Commodity price risk management" below.

(E) COMMODITY PRICE RISK MANAGEMENT

The following is a summary of NYMEX West Texas Intermediate ("WTI") light sweet oil fixed price contracts in effect:

Daily quantity	Remaining term of contract	Fixed price per bbl
1,000 bbls per day	January 1 to December 31, 2011	CA$ 90.00
1,000 bbls per day	February 1 to December 31, 2011	CA$ 91.80

The fair value of the remaining term of the above crude oil contracts, mark-to-market at December 31, 2010 is a liability of $2.4 million. If the WTI price increases (decreases) by $1.00 per bbl, the fair market value of these contracts would increase (decrease) by $0.7 million.

(F) LIQUIDITY RISK

Liquidity risk is the risk the Company will encounter difficulties in meeting its financial liability obligations. The Company's financial liabilities are comprised of accounts payable, accrued liabilities and bank debt.

During 2010, oil and gas companies have faced a number of challenges resulting from a strengthening Canadian dollar relative to the US dollar, weakening natural gas prices and relatively tight credit and equity markets. The Canadian economy appears to be improving and there are signals that the recession that began in late 2008 may be coming to an end.

The Company manages liquidity risk through the prudent use of debt, interest rate, currency and commodity price risk management and through an actively managed production and capital expenditure budget process.

Celtic has a committed facility which matures on June 28, 2011 and may be extended for an additional 364 days with the consent of the lenders. An interim review was conducted by the financial institutions in the fourth quarter of 2010 and the borrowing base of $215M was reconfirmed. Although management expects that the financial institutions will extend the facility in 2011, there can be no assurance that the financial institutions will choose to do so. Should the financial institutions not extend the loan the Company would need to seek alternative forms of debt or equity financing or dispose of certain assets to repay the outstanding indebtedness.

(G) CAPITAL STRUCTURE

The Company's capital structure is comprised of shareholders' equity, bank debt and working capital. Celtic's objectives when managing its capital structure is to maintain financial flexibility in order to meet financial obligations, as well as to finance future growth through capital expenditures relating to exploration, development and acquisition activities.

The Company monitors its capital structure and short-term financing requirements using a net debt to trailing funds from operations ratio, a non-GAAP financial measure.

	December 31, 2010	December 31, 2009
Bank debt	$ 160,800	$ 173,900
Working capital (surplus) deficiency (1)	39,948	(5,691)
Net debt	$ 200,748	$ 168,209
Trailing funds from operations (2)	$ 122,500	$ 168,012
Net debt to trailing funds from operations ratio	1.64	1.00

(1) Working capital excludes bank debt and unrealized gains or losses on financial instruments and associated income taxes.

(2) Trailing funds from operations is annualized based on the most recent quarter's funds from operations which is calculated as cash provided by operating activities before settlement of asset retirement obligations and change in non-cash operating working capital.

Celtic targets a net debt to trailing funds from operations ratio of less than 2.0 times. The Company manages its capital structure and makes adjustments according to market conditions in order to maintain flexibility to achieve its objectives stated above. To adjust its capital structure, the Company may increase or decrease capital expenditures, issue new shares, issue new debt or repay existing debt.

11. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital, excluding bank debt:

Twelve months ended December 31	2010	2009
Accounts receivable	$ 6,242	$ (11,756)
Drilling royalty credits	10,252	(13,159)
Prepaid expenses and deposits	77	(938)
Accounts payable and accruals	29,670	(2,839)
Change in non-cash working capital	$ 46,241	$ (28,692)
Relating to:		
Operating activities	$ 24,622	$ (13,261)
Investing activities	21,619	(15,431)
Change in non-cash working capital	$ 46,241	$ (28,692)

During the reporting period, the Company made the following cash outlays in respect of interest expense:

Twelve months ended December 31	2010	2009
Interest	$ 5,559	$ 5,160

12. RELATED-PARTY TRANSACTIONS

The Company has retained the law firm of Borden Ladner Gervais LLP ("BLG") to provide Celtic with legal services. William C. Guinan, a director, chairman and corporate secretary of Celtic is a partner of this law firm. During the twelve months ended December 31, 2010, the Company incurred $0.3 million (2009 - $0.3 million) to BLG for legal fees and disbursements. These amounts have been recorded at the exchange amount. The Company expects to continue using the services of this law firm from time to time.

13. CONTINGENCIES

Celtic and SemCAMS were parties to a confidential KA Plant Inlet Gas Purchase Agreement (the "KA Plant IGPA"). SemCAMS entered into proceedings under CCAA on July 21, 2008. Celtic and SemCAMS were in disagreement with respect to whether the terms under the KA Plant IGPA should have remained in force subsequent to July 21, 2008. The courts ruled in favour of SemCAMS with respect to disputed processing fee charges from July 22, 2008 to November 30, 2009. As a result, Celtic has recorded a loss on disputed processing fees in the amount of $4.7 million in 2010.

CORPORATE INFORMATION

BOARD OF DIRECTORS

ROBERT J. DALES [2, 3, 4]
President, Valhalla Ventures Inc.

WILLIAM C. GUINAN [1, 5]
Partner, Borden Ladner Gervais LLP

ELDON A. MCINTYRE [2, 3, 4]
President, Jarrod Oils Ltd.

NEIL G. SINCLAIR [2, 4, 5]
President, Sinson Investments Ltd.

DAVID J. WILSON [3, 5]
President & Chief Executive Officer, Celtic Exploration Ltd.

OFFICERS

DAVID J. WILSON
President & Chief Executive Officer

SADIQ H. LALANI
Vice President, Finance & Chief Financial Officer

MICHAEL R. SHEA
Vice President, Land

ALAN G. FRANKS
Vice President, Operations

1 Chairman of the Board
2 Member of the Audit Committee
3 Member of the Reserves Committee
4 Member of the Compensation Committee
5 Member of the Disclosure Committee

HEAD OFFICE

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REGISTRAR AND TRANSFER AGENT

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Calgary, Alberta T2P 4H2

BANKERS

NATIONAL BANK OF CANADA
Suite 2700, 530 Eighth Avenue S.W.
Calgary, Alberta T2P 3S8

AUDITORS

PRICEWATERHOUSECOOPERS LLP
Suite 3100, 111 Fifth Avenue S.W.
Calgary, Alberta T2P 5L3

EVALUATION ENGINEERS

SPROULE ASSOCIATES LIMITED
Suite 900, 140 Fourth Avenue S.W.
Calgary, Alberta T2P 3N3

STOCK EXCHANGE LISTING

TORONTO STOCK EXCHANGE
Trading symbol "CLT"

CELTIC'S ANNUAL AND SPECIAL MEETING OF SHAREHOLDERS

Celtic's Annual Meeting of shareholders will be held on Thursday, April 21, 2011 at 3:00 p.m. in the Grand Lecture Room at The Metropolitan Centre 333 - 4 Ave. S.W. Calgary, Alberta.

ABBREVIATIONS

bbls	barrels
mbbls	thousand barrels
bbls/d	barrels per day
BOE	barrels of oil equivalent
mBOE	thousand barrels of oil equivalent
BOE/d	barrels of oil equivalent per day
mcf	thousand cubic feet
mmcf	million cubic feet
bcf	billion cubic feet
mmcf/d	million cubic feet per day
mmbtu	million British Thermal Units
MD&A	Management's Discussion and Analysis
GJ	gigajoules
T	tonnes
MT	thousand tonnes
AECO-C	Alberta Energy Company "C" Meter Station of the Nova Pipeline System
API	American Petroleum Institute
ARTC	Alberta Royalty Tax Credit
CICA	Canadian Institute of Chartered Accountants
BIT	before income taxes
WTI	West Texas Intermediate

CONVERSION OF UNITS

Imperial = Metric
1 acre = 0.4 hectares
2.5 acres = 1 hectare
1 bbl = 0.159 cubic metres
6.29 bbls = 1 cubic metre
1 foot = 0.3048 metres
3.281 feet = 1 metre
1 mcf = 28.2 cubic metres
0.035 mcf = 1 cubic metre
1 mile = 1.61 kilometres
0.62 miles = 1 kilometre
1 mmbtu = 1.054 GJ
0.949 mmbtu = 1 GJ

Natural gas is equated to oil on the basis of 6 mcf = 1 BOE.

Designed and produced by Foundry Creative Inc.

Celtic EXPLORATION LTD.

CELTIC'S NEW ADDRESS EFFECTIVE MAY 1, 2011:

SUITE 600, /
WEST TOWER
321 SIXTH AVENUE,
SOUTH WEST /
CALGARY, ALBERTA
T2P 3H3 /
WWW.CELTICEX.COM